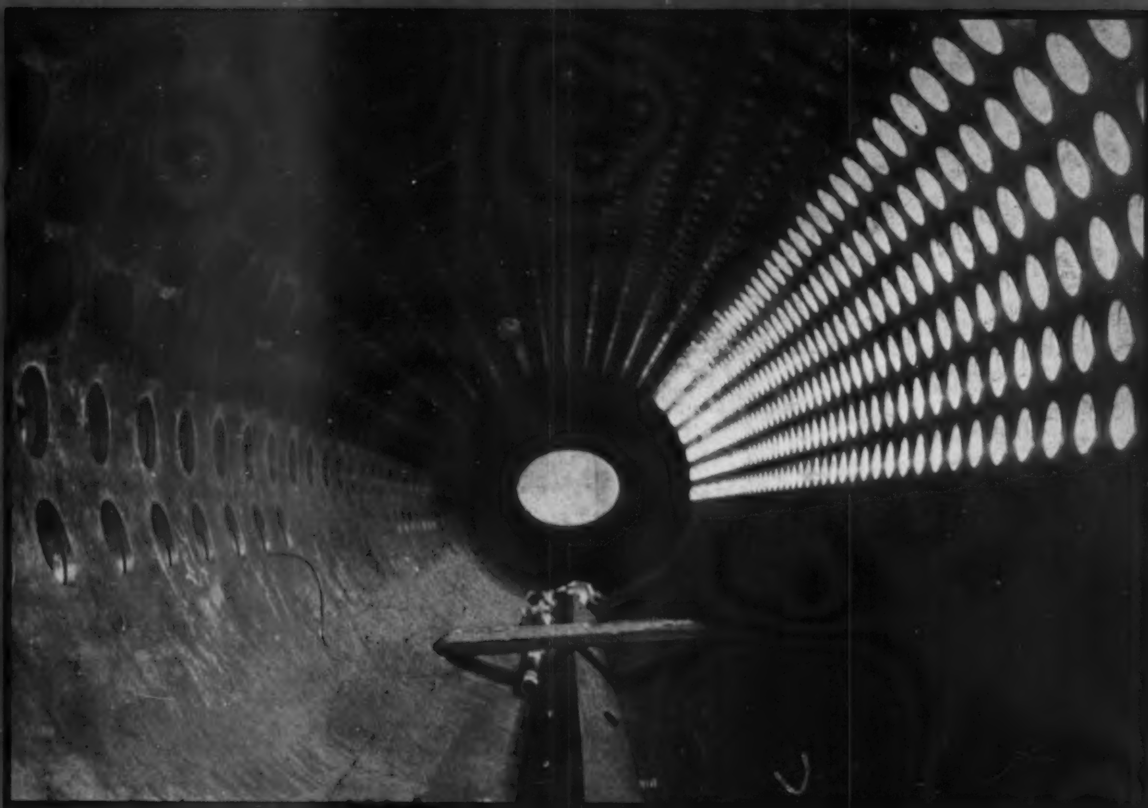
COMBUSTION

DEVOTED TO THE ADVANCEMENT OF STEAM PLANT DESIGN AND OPERATION

February, 1942



Inside of lower drum during erection of unit mentioned on page 37

Power from Process Steam ▸

Grate Temperatures a Measure of Ignition Penetration ▸

The BTU Values of a Coal ▸

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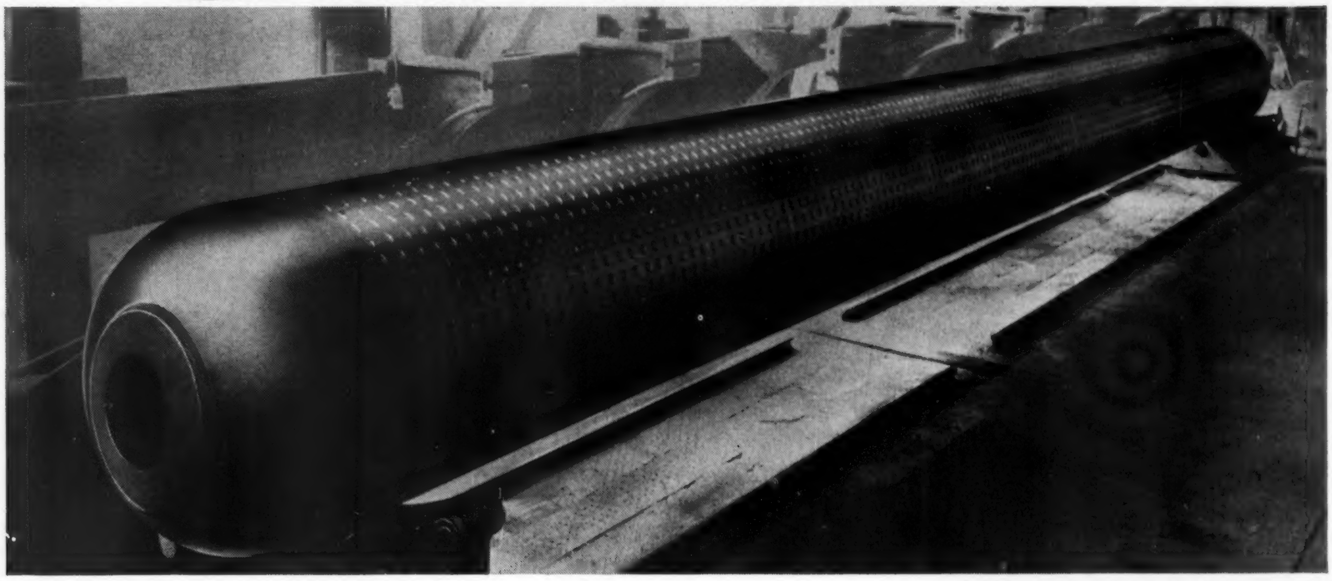

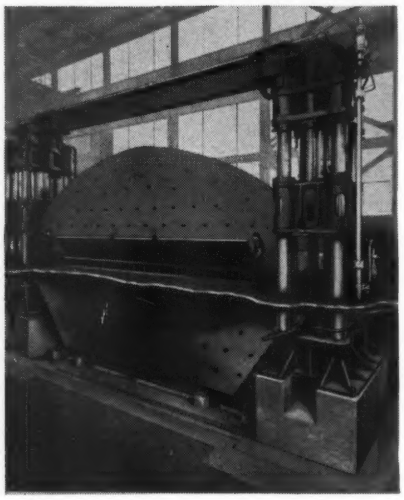

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COMBUSTION

DEVOTED TO THE ADVANCEMENT OF STEAM PLANT DESIGN AND OPERATION

VOLUME THIRTEEN NUMBER EIGHT

CONTENTS

FOR FEBRUARY 1942

FEATURE ARTICLES

EDITORIALS

DEPARTMENTS

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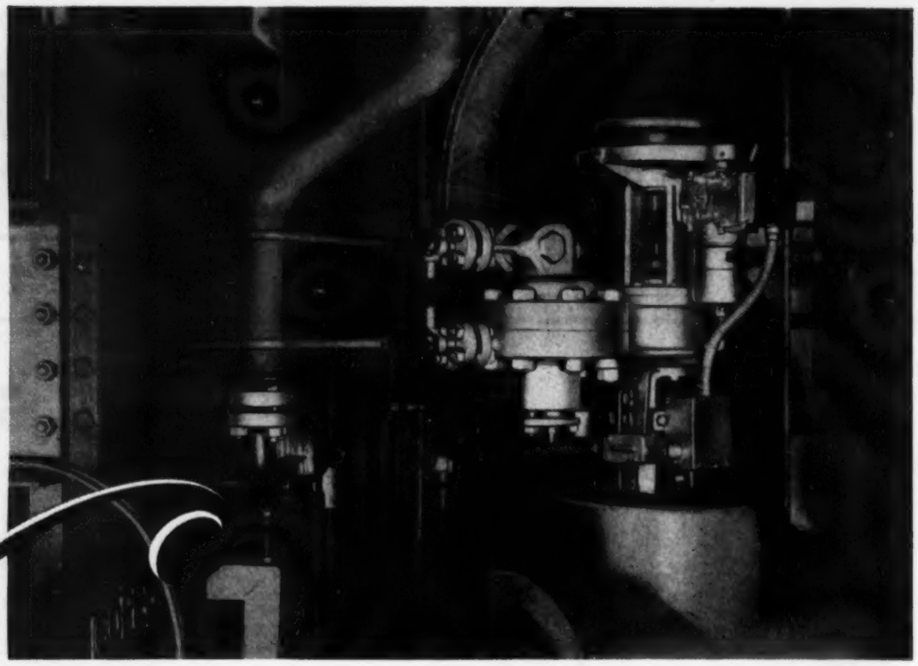

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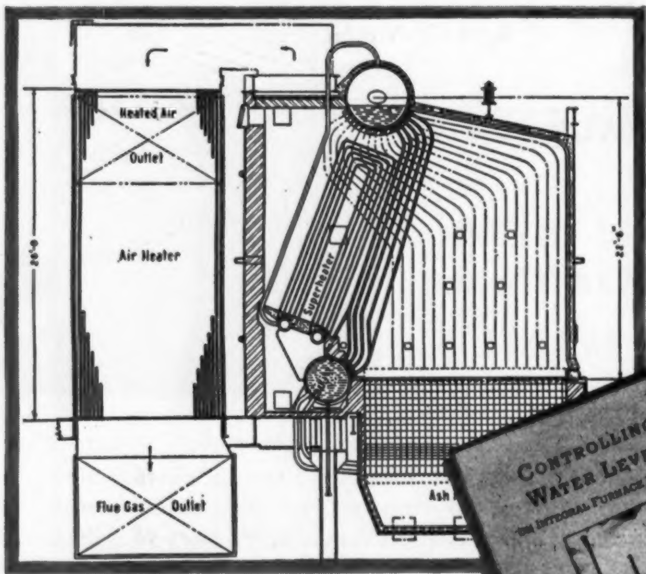

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E D I T O R I A L

Coal Stocks

Despite the fact that stocks of coal held by consumers were appreciably greater on January 1, 1942 than they were a year ago, Howard A. Gray, Acting Director of Solid Fuels Coordination, has warned that consumers who continue their customary prewar stocking practices may expect to find themselves in a precarious position later on as demands upon transportation facilities increase with expanding war production. Mining capacity appears adequate to meet all probable requirements, with present production running about 90 per cent of capacity, and consumers are advised to take advantage of the present coal production and transportation capacity to build up their stock piles.

According to the latest Government figures, electric utilities average over two months' supply on hand, with as much as five months' in individual cases; but industrials average only about a month's supply, with many very much less. Lack of storage space and rehandling facilities probably account for low stocks in many cases although such limitations could probably be overcome were the situation to be fully appreciated.

Coal is the backbone of our production and many will recall what happened in some localities at one period during the last war when it often became necessary to attempt to burn anything bearing the label of coal. It is not to be inferred that this experience is likely to be repeated, for the country's transportation systems are in much better position to cope with added demands than they were in 1917–1918. Nevertheless, they are certain to be heavily taxed in some regions and if grades of coal best adapted to particular fuel-burning equipment are to be had, sufficient storage to carry over such periods is the best assurance against operating difficulties.

Shifting Reserve Capacity

A prudent amount of reserve capacity has always been desirable for meeting unanticipated demands and assuring uninterrupted service. This is even more essential in time of war than in ordinary times, as was borne out last year in the utility field where the increased capacity installed during the year fell short of the increased load by over half a million kilowatts.

As the availability of boilers, turbines and other power plant equipment has steadily increased through improvements in design and operating experience, and as interconnection has been extended, the necessary reserve has decreased. This has been quite noticeable during the last decade in both utility and industrial power plants. Despite this, considerable excess reserve capacity appears to exist in individual cases, due to the installation of more efficient equipment or perhaps to a divergence of opinion as to what constitutes prudent reserve, which obviously will be governed by local conditions.

There are indications that much of the reserve equipment that can safely be spared may be drawn upon to meet urgent needs in other plants whose operation would be delayed by awaiting delivery of new equipment. Already, some idle boilers and turbines are understood to be in the process of removal from two utility plants to serve a large munitions plant now under construction in another section of the country. In other cases, deliveries of turbines under construction have been diverted to other plants by order of the Government.

It has been suggested that in certain localities pooling of central station and industrial power capacity might be desirable, particularly plants of those non-essential industries, which by reason of curtailed output should have excess power capacity available. While this might be possible in a few instances, most large plants falling within this category are being wholly or partially converted to some form of war production, and the smaller plants are not so set up as to permit feeding power to a utility system. Hence, this cannot be regarded as a substantial source of reserve.

However, should unforeseen load demands jeopardize the required reserve in some cases, before new capacity can be made available, resort can always be had to curtailment of non-essential load.

Aliens in Defense Work

The Labor Division of the War Production Board has just issued a release intended to clarify the situation as concerns the employment of aliens in defense work. It says: "Where a war contract is not classified by the Army or Navy as *secret, restricted* or *confidential*, there is no law or ruling which prevents employers from using aliens, and even where a contract is so classified there may be exceptions under which approval can be secured."

This is intended to prevent the exclusion of unnaturalized workers who are a source of manpower important to the attainment of our war production goals and to avoid a repetition of incidents in which some such employees have been discharged through mistaken ideas as to the Government's attitude in such cases. To this extent the ruling seems both logical and prudent.

However, in view of the extreme precautions now being adopted to guard all war production plants and the censorship evoked concerning their operations, some may question the wisdom of a further statement of the Labor Division to the effect that there should be no distinction between the employment of aliens of *enemy* countries and those from other nations, the sole test being the individual's loyalty to the United States. Granted that there are thousands of enemy aliens, so classified, who are loyal to the ideals of this country, special care in applying this test would seem imperative.

Although no specific reference is made to power plants, whose operation in many cases is vital to the war effort, one would infer that they are covered by the ruling.

POWER FROM PROCESS STEAM

By EVERETT E. THOMAS
Industrial Engineering Dept.
General Electric Company

Exhaust steam at atmospheric pressure is shown to be adequate for the majority of process requirements; curves are included to indicate the power gain through increased initial pressure and decrease in exhaust pressure; and the economics of condensing and noncondensing operation are discussed, as well as the employment of topping units in industrial plants.

INDUSTRIALS and utilities approach their power plant problems with two major differences in concept. Utilities can afford to install additional feedwater heaters and other heat cycle refinements for gaining a few per cent in plant efficiency because electrical power is their product for sale and they use a relatively long period for amortization. On the other hand, power may represent less than ten per cent of the cost of the product for sale by industrials, which means they cannot afford as much power plant refinement. Furthermore, industrials usually amortize such investments within two to five years. Both parties may be served to mutual advantage by joint firm operations where by-product power is potentially available.

Process Steam

Many men conversant with processes think of heat requirements in terms of steam temperature or pressure instead of so many British thermal units (Btu) which is the true measure for drying and heating purposes. As a matter of fact, processes need only the latent heat in the steam unless one is concerned with operations such as cooking in digesters and vulcanization of rubber. Such uses represent only a small percentage of industrial steam.

Fig. 1 shows the relation of steam temperature, pressure and heat content, or enthalpy, as British thermal units per pound of water and/or steam for the usual industrial range. Wet steam represents the latent heat; that is, the amount of heat needed to evaporate one pound of water to dry-saturated steam at the same temperature. The dashed line in Fig. 1 indicates the small amount of heat content in the steam which may be made available for power from initial steam conditions of 200 lb per sq in. gage and 100 deg F superheat. For instance, we can use only eleven per cent of the heat content for power if we start with these steam conditions and exhaust to process at atmospheric pressure.

We can extract steam table data for dry-saturated steam as follows:

TABLE 1

	Process Steam		Enthalpy or Heat Content		
Pressure, Lb Gage	Temperature, Degrees F	Volume, Cu Ft/Lb	Liquid, Btu	Evaporation, Btu	Total, Btu
0	212	27.2	180	970	1150
5	227	20.4	195	960	1155
10	240	16.5	208	952	1160
15	250	13.9	218	945	1163
20	259	12.0	227	939	1166
25	267	10.6	235	934	1169
30	274	9.5	243	929	1172
40	287	7.8	256	919	1175
50	298	6.7	267	911	1178
75	320	4.9	290	894	1184
100	338	3.9	309	880	1189
125	353	3.2	325	868	1193
150	366	2.75	338	857	1195
175	377	2.40	351	846	1197
200	388	2.13	362	837	1199

It is seen that total heat in dry-saturated steam remains essentially constant over the steam pressure range

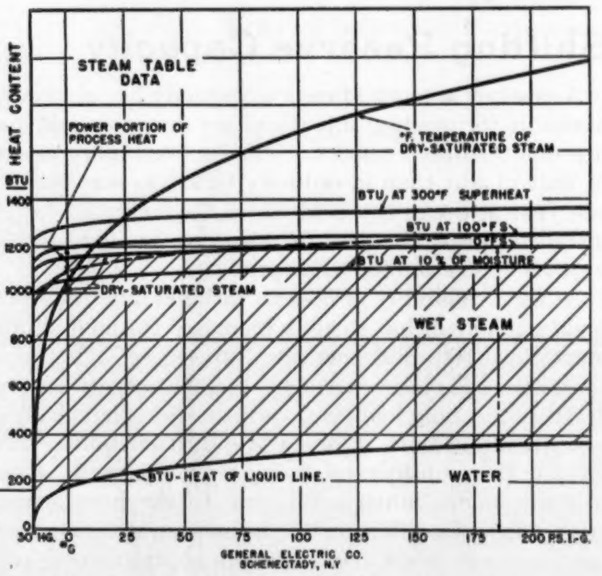

Fig. 1—Steam table data for usual process steam range

On December 3, 1941, Mr. Thomas gave an informal talk on the above subject at a luncheon meeting of a small group of industrial power engineers of the A.S.M.E. With the thought that the subject is of interest to a very large number of engineers, he was subsequently asked and kindly consented to prepare the present article for COMBUSTION, which incorporates many of the ideas expressed on that occasion.—EDITOR.

from atmospheric pressure to 200 lb per sq in. gage for all practical purposes. In other words, steam at atmospheric pressure should be able to serve all processes that do not require temperatures maintained above 200 F. The difficulty is mechanical; that is, larger steam space is required per pound of steam at lower pressures, as shown in Table 1. The problem becomes simply a matter of overall economics.

More by-product power may be obtained if the process steam is expanded to a lower pressure by the use of a noncondensing steam turbine-generator unit as a pressure-reducing valve. Representative kilowatt gains are expressed approximately as in Table 2.

It is seen that the by-product power gain is at an increasing rate as the turbine exhaust pressure is lowered. Furthermore, the higher initial pressure provides greater energy for conversion into power as indicated. There are so many variables to be considered when relating power to process steam that it is advisable to make an inclusive engineering study in each individual case.

Evidently industrials should find it profitable to coordinate their process equipment with their power requirements. Although such procedure may call for more expensive process apparatus and piping, the power gain from process steam may justify the extra capital expense. One method for obtaining lower turbine exhaust or extraction steam pressure for process use is to install a suitable air removal ejector or pump on the discharge end of the process apparatus if its condensed steam is not mixed with the ingredients of the product being manufactured.

Modern Turbines

For a given rating and type of turbine, the inlet and exhaust pressures determine the size of passage required to admit the steam, the size of opening required to exhaust it, the number of stages needed to get the most power out of the steam, and the number of pounds of steam required for generating power to meet the unit rating. The ratio of inlet pressure to exhaust pressure is an approximate measure of the amount of energy in the steam available for conversion into power. This ratio has much to do with fixing the physical size of the turbine by its effect on the number of stages or length and its effect on the steam flow or area.

The greater part of the heat put into the steam by the boiler is of no use for power. Furthermore, the heat of vaporization in the exhaust steam may be used for heating and process purposes. Noncondensing turbines skim off that portion of the heat energy which is usable for power and discharge the rest of the heat to building heating and process lines. Under such conditions, industrial processes can be charged with a large share of the heat and the turbine charged only with that which it converts into power and its losses. Power can be had at the lowest possible fuel cost wherever a noncondensing turbine may be so used.

TABLE 2

Process Steam Pressure, Lbs, Gage	Available Kilowatts in 100,000 Lb of Steam per Hour — Initial Steam 200 Lb Gage, 100° F Superheat		Initial Steam 400 Lb Gage, 100° F Superheat	
	Total Kw	Gain Kw	Total Kw	Gain Kw
100	1000	..	2300	..
75	1500	500	2700	400
50	2100	600	3300	600
25	3000	900	4100	800
0	4400	1400	5400	1300
1" Hg abs	8300	3900	9000	3600

Condensing turbines, however, must be charged with all of the heat in the steam delivered to them from the boiler unless the condenser is an evaporator or supplies hot water for process. Usually more than two-thirds of the heat delivered is that given up when the steam changes back to water in the condenser. This heat cannot be used for power so it must be discarded, thereby greatly increasing the fuel cost of a condensing turbine relative to a noncondensing turbine supplying process steam.

Fewer total pounds of steam will be required for generating a given amount of power when the available energy is large than when it is small; that is, steam admitted to a turbine at a high pressure and exhausted at a very low

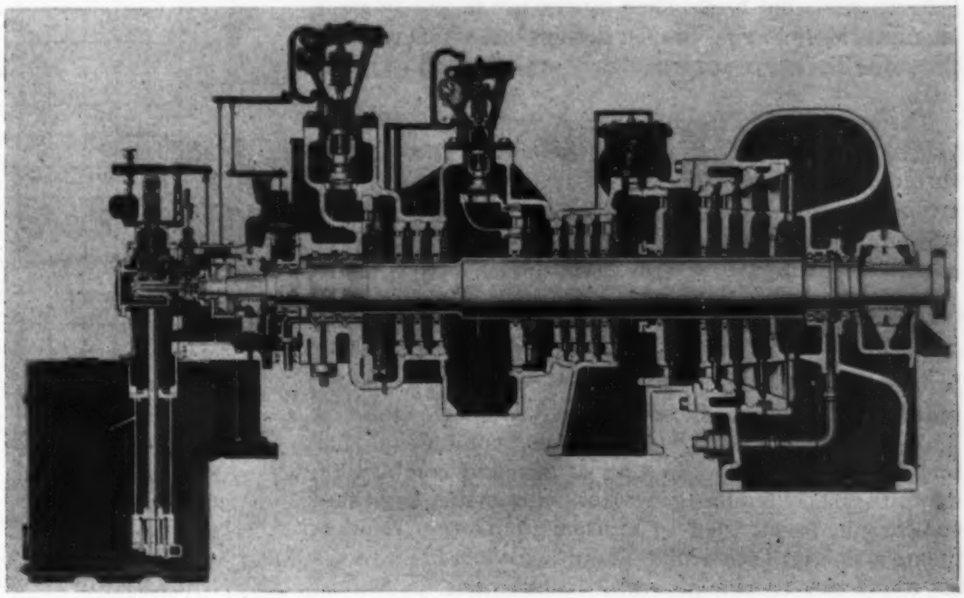

Fig. 2—Cross-section of double-automatic-extraction condensing steam turbine

pressure will have much energy available for power, but steam admitted at a pressure only slightly higher than the exhaust pressure will have very little energy available for power. A very short energy range should be avoided for economic reasons.

It should be noted that steam conditions must be identical if steam rates of different turbines are to be compared.

Turbine-Generator Units

Fig. 2 shows a longitudinal section through a double-automatic-extraction, condensing steam turbine. It will be observed that this combines all elements of the simpler turbine forms into one machine. The higher extraction pressure is controlled by cam-operated poppet valves similar to the first-stage admission valves but a ring-grid valve is used for maintaining the lower extraction pressure. Their controls are oil-relay operated and linked back to the pilot valve of the speed governor which provides close speed regulation owing to its sole function as a speed-indicating instrument.

The double-automatic-extraction feature is desirable when applied to the larger industrial sizes of steam turbines, but is not practicable for the smaller ones. The latter case should be satisfied by the use of two or more steam turbines having simpler designs but which produce the same desired result when they are operated in parallel.

The operating, or speed governor, usually has a regulation of three or four per cent of the normal speed of the turbine. Stable governors having relatively broad regulations for instantaneous load changes can maintain substantially zero regulation for a settled change if the governor is equipped with a regulation corrector.

Modern practice is to install a surface air cooler as a part of the generator and its exciter cooling system. The resulting closed ventilating system eliminates large external air ducts and provides benefits such as greatly reduced fire hazard, since the closed system contains a limited volume of air to support any combustion that might occur. The elimination of dirt and combustible deposits greatly reduces generator maintenance and these coolers can be adapted to unusual foundation requirements which is of particular advantage when fitting coolers to existing turbine-generator installations.

Power Plant Auxiliaries

One of the most important factors in continuity of power service is reliability of the auxiliary equipment. There was a trend from steam drives to motor-driven auxiliaries about ten years ago due to improved electrical designs and development of mechanical equipment, such that it became less necessary to have variable-speed drives for fans, coal pulverizers, boiler-feed pumps, and circulating-water pumps. Furthermore, the advent of much higher boiler pressures and temperatures made the small steam turbine less attractive owing to increased cost and lower efficiency associated with such higher pressures and temperatures.

Electric drive for essential auxiliaries is favored from the standpoint of convenience and cleanliness in operation as well as ease of adaptation to automatic and remote control. Furthermore, it eliminates much congested piping. The overall fuel economy is about the same whether or not motor drives are used instead of turbine drives for all auxiliaries. The usual practice is to include one turbine-driven boiler-feed pump for standby and emergency service. Some stations use a house turbine-generator set to provide means for starting if the power station is isolated from other sources of electrical power. Whether or not other standby turbine-driven auxiliaries should be used will depend upon local circumstances and preferences.

Power Gains

It has already been shown what it means to take by-product power from process steam by the use of noncondensing and/or extraction-condensing turbine-generator units. Fig. 3 shows the amount of power available if a low-pressure condensing turbine-generator unit is used for saving waste steam from existing noncondensing turbines or steam engines, hammers, heating line returns or other sources of low-pressure steam. A variation of this idea would be to use a mixed-pressure condensing unit which would receive makeup steam from the main boiler header.

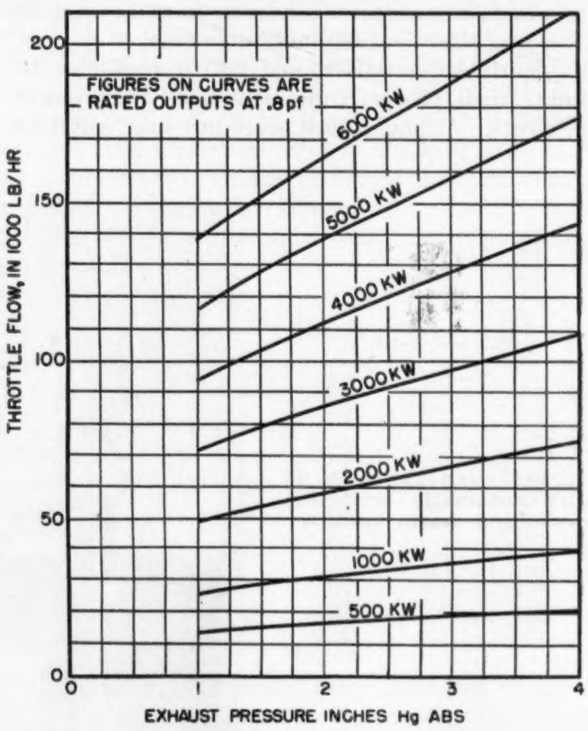

Fig. 3—Power available in waste steam, with low-pressure condensing turbine for initial steam conditions of 0 lb gage and no superheat

Iron & Steel Engineer—L. E. Newman

Fig. 4 indicates the amount of power made available by a high back-pressure or "topping" turbine-generator unit which receives steam from a modern, high quality, high-pressure boiler and exhausts into the present boiler header. The better efficiency of such a new boiler may permit these power gains without burning additional fuel.

The binary cycle may be used for obtaining more by-product power from the process steam. Such a system is the mercury-steam cycle superposed on steam turbines or existing power stations.[1] This cycle permits the genera-

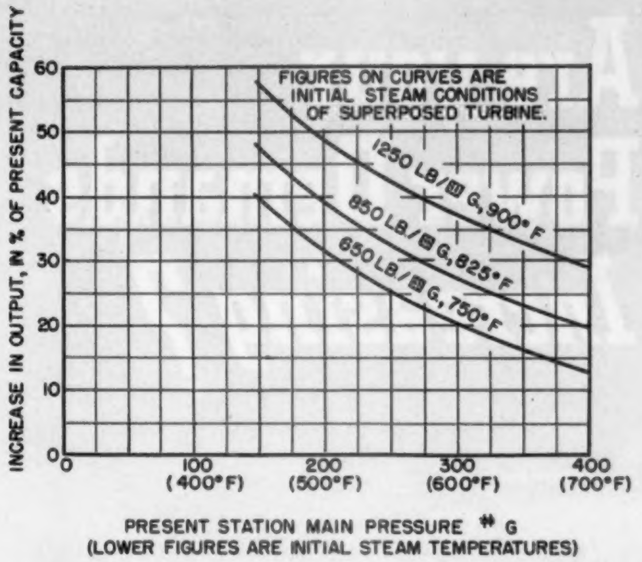

Fig. 4—Additional power from higher steam pressures and temperatures—"Topping." Minimum increase in output expected from the same total quantity of fuel burned when a new turbine and boiler are superposed on an existing station exhausting at 2 in. Hg abs

Iron & Steel Engineer—L. E. Newman

tion of steam at existing boiler pressures and still gain much more by-product power than can be obtained from a high back-pressure or "topping" steam turbine installation. In fact, the mercury-steam power unit may top the present "topping" steam unit to advantage.

A further additional power gain may be realized by making a "thoroughfare" desuperheater a part of the heat-balance cycle as indicated in Fig. 5. This is an improved system for the application of noncondensing and/or extraction-condensing turbine-generator units to process steam requirements by transferring the high-level heat represented by the superheat in the exhaust steam to the feedwater supplied to the boiler. In other words, it becomes a closed boiler feedwater heater which permits economical use of much higher initial steam temperatures and still provides process steam at a constant temperature; usually dry-saturated.

[1] For an extensive discussion of this subject see papers on "The Mercury-Vapor Process" by A. R. Smith and E. B. Thompson, and "Mercury for the Generation of Light, Heat, and Power" by H. N. Hackett at the A.S.M.E. Annual Meeting, December 3, 1941.

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To Study Effects of Daylight Saving

Chairman Olds of the Federal Power Commission announces that the Commission's staff will make a careful study of the records of the electric utility systems over the country, covering certain periods before and after the beginning of "war time," in order to measure its total effect on the saving of electricity. Last June estimates indicated that, by setting clocks ahead one hour, about 750,000 kw capacity would be saved, but since then the program has expanded tremendously. Hence, the findings of the Commission's study should prove most informative.

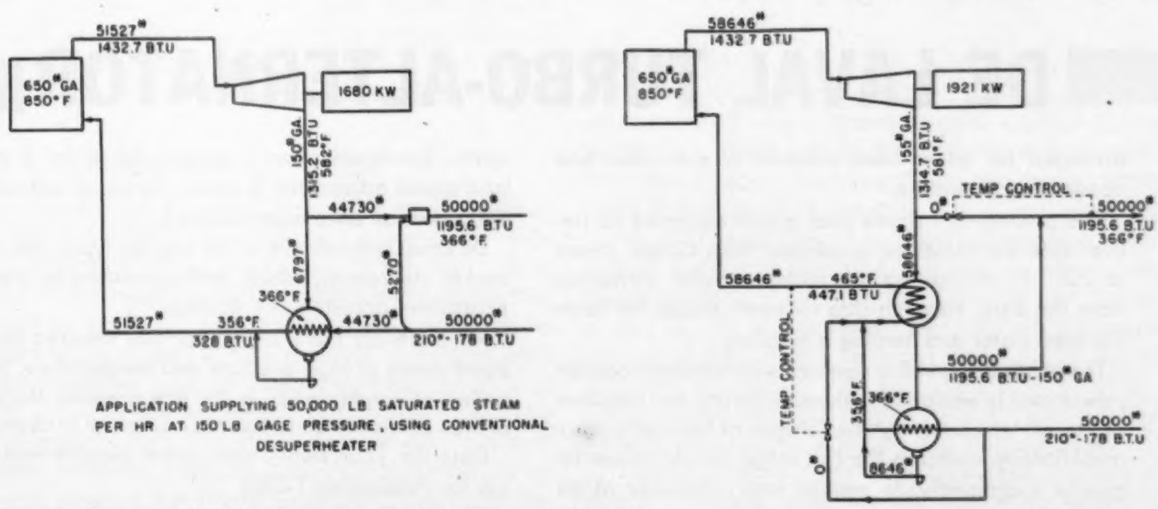
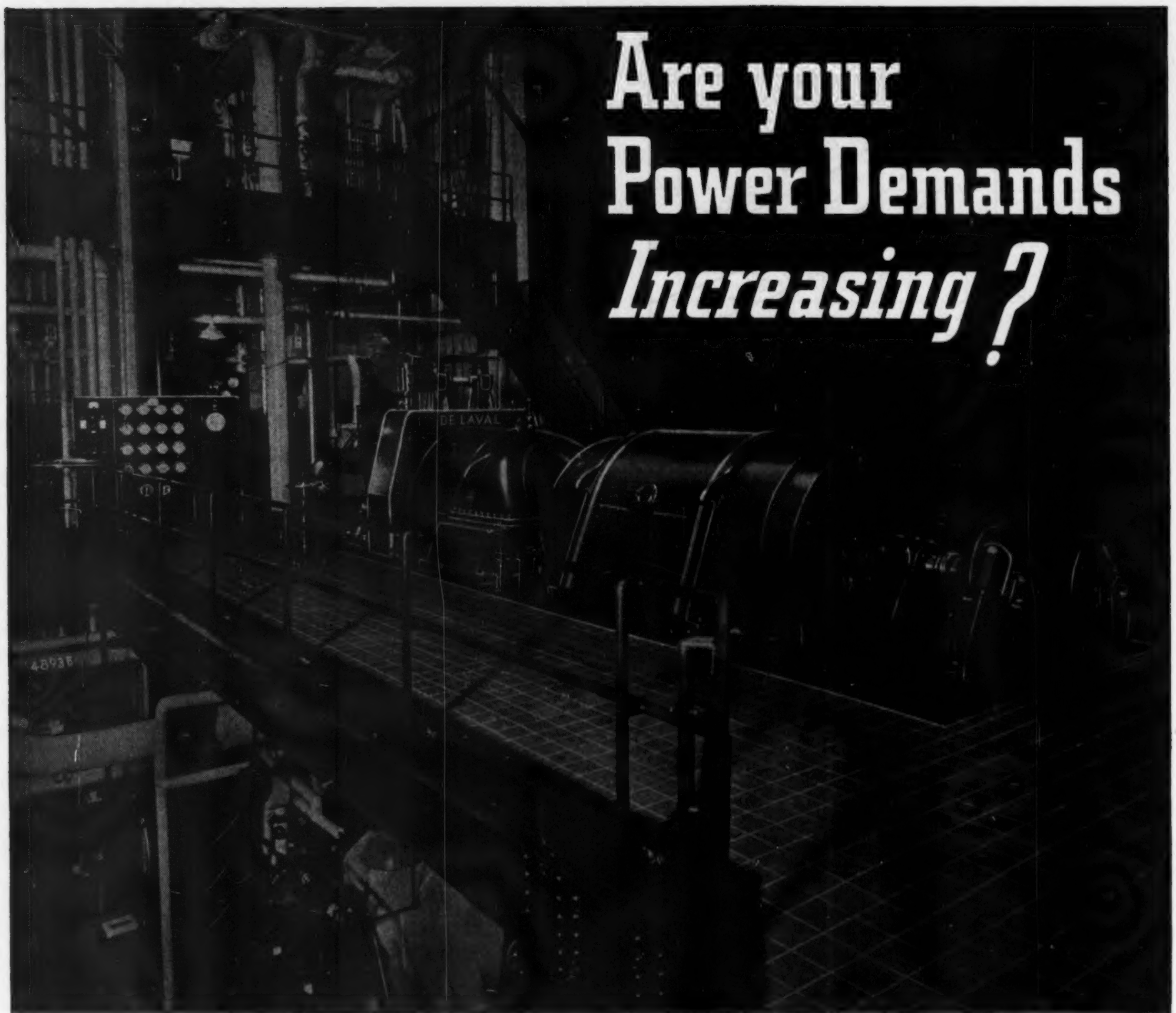


Fig. 5—Power gain by the use of the "Thoroughfare" desuperheater

A.S.M.E.—H. W. Cross and E. S. Wells, Jr.

APPLICATION OF THOROUGHFARE DESUPERHEATER AND FEEDWATER HEATER TO SUPPLY 50,000 LB SATURATED STEAM PER HR AT 150 LB. GAGE PRESSURE



Are your
Power Demands
Increasing ?

Grate Temperatures a Measure of Ignition Penetration

Knowing the rate of ignition penetration of a stoker fuel bed it is possible to apply air for combustion most effectively in each zone. A convenient means of ascertaining the ignition penetration is through measurement of grate temperatures by means of thermocouples. Directions for their installation and use are given.

By WALTER H. WOOD

Service Engineer,

Combustion Engineering Company, Inc.

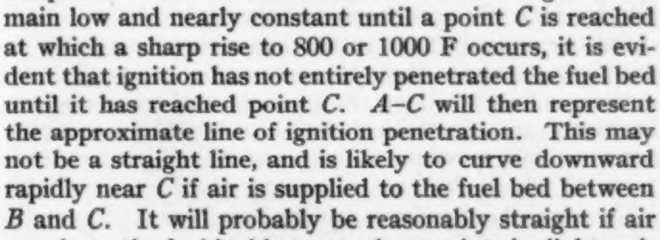
IF IT were possible to look at a longitudinal cross-section of a fuel bed on a stoker in operation, some very interesting and valuable information pertaining to fuel burning would be available. An operator can see only the surface of a fuel bed, and even that rather indistinctly under certain conditions. It is not possible to know, by looking at the surface of a fuel bed, just how rapidly ignition is penetrating the fuel. But if the rate of penetration of ignition were known, it would be a help in applying air for combustion most effectively in each zone of a stoker. This would be true of any fuel, but particularly in the case of those fuels such as anthracite, coke breeze and lignite, which are ignited with more difficulty than are most bituminous coals.

In all types of stokers, the fuel burning starts with ignition on the surface of the bed as the fuel enters the furnace, and continues until only ash and some unburned carbon remain on the grate. The rate at which ignition can be made to penetrate the fuel bed is a factor that influences or governs the capacity, and to a large extent, the efficiency that can be developed by a steam generating unit. This rate will depend on the character of the fuel, the design of the furnace and the application of air to the ignited fuel. In general, it is advisable to establish as rapid penetration as possible over each zone or compartment of a stoker, taking care not to use air in such quantity as will retard combustion or cause too much fine fuel to be lifted from the bed and carried away in the gas stream. On the other hand, if sufficient air is not employed in a zone, the maximum effect from that zone will not be obtained. Combustible gases will be distilled from the fuel, and such gases may not be mixed with sufficient oxygen within the furnace to complete their burning; hence smoke or excessive carbon monoxide loss will result.

Reactions Through Fuel Bed

The air supply for burning fuel on a stoker passes through the grate and rises through green fuel, then comes in contact with ignited pieces of the fuel. The quantity of air is usually sufficient to burn the first bit of ignited carbon to CO_2. But as that gas continues to pass upward through ignited fuel, it comes in contact with incandescent carbon, and at least a part of the CO_2 is reduced to CO. If the air supply is insufficient for the amount of ignited fuel, the result will be low fuel bed temperature, retarded burning and slow penetration of ignition. If, instead, too much air is passed through the fuel bed the ignited fuel may be chilled and combustion retarded.

Since it is not possible to examine a cross-section of a burning fuel bed, any other means of studying the rate at which ignition penetrates the fuel has an important bearing on successful operation. Measuring the temperature of the grate surface underneath the fuel is of definite value in this connection. Naturally, that part of the grate surface which is covered with green fuel is relatively cool, compared with a surface on which the fuel has reached ignition temperature. In the accompanying sketch the line *A–D* may represent the surface of a fuel



Sketch indicating ignition zone

bed of initial thickness *A–B*, carried on a grate *E–F*. If temperatures measured at short intervals along *B–F* remain low and nearly constant until a point *C* is reached at which a sharp rise to 800 or 1000 F occurs, it is evident that ignition has not entirely penetrated the fuel bed until it has reached point *C*. *A–C* will then represent the approximate line of ignition penetration. This may not be a straight line, and is likely to curve downward rapidly near *C* if air is supplied to the fuel bed between *B* and *C*. It will probably be reasonably straight if air supply to the fuel bed between these points is slight or is withheld altogether. In the latter case point *C* will be found further along the grate, as at *C′*, and the line representing penetration ignition will become *A–C′*.

Having located point *C* or *C′* where ignition penetration is complete, it is evident that the triangle *A–B–C′* represents green or unignited fuel, while the triangle *A–D–C′* represents ignited and burning fuel, and *C′–D–F*, the resulting ash. The closer the points *C* or *C′* can be brought to *B* for a given length of fuel bed the

greater will be the quantity of ignited fuel ready to respond to a sudden load demand. At the same time, the more rapid will be the rate of penetration of ignition, and the more effective the air supply. The likelihood of distilling unburned combustible gases from the fuel bed will then be reduced.

The ignited fuel should be burned by the air supplied under the entire length *B–F*. Each integral part of the entire fuel bed length should be supplied with the correct amount of air for combustion, commensurate with the depth of the ignited part of the fuel bed. If that is done, the entire fuel bed will burn most effectively and the thickness of the fire will be gradually reduced from the front toward the rear of the furnace. An exception is found in the case of coking coals burned on underfeed stokers. Such coals "swell" upon coking and have a tendency to produce a thick fuel bed, but with proper operation of secondary rams and the correct use of air, the coke masses can be broken down so as to give the fuel bed a slight taper from front to rear of the stoker.

Air Supply When Burning Anthracite at Low Combustion Rates

With traveling-grate stokers in rear-arch furnaces, when burning anthracite buckwheat at very low combustion rates, it is not always possible to apply air under the entire length of the fuel bed. To do so would reduce the combustion rate at the rear of the fuel bed so low that insufficient incandescent fuel would be carried forward to maintain ignition. Under such conditions of very low burning rates, it may be necessary to cut off the air supply altogether at the front, and to reduce it materially toward the end of the fuel bed's length. This applies also to lignite and coke breeze that are of such sizing as to make ignition difficult. When operating in this manner, that is, with air for combustion applied only at the rear portion of the grate, the point at which ignition completely penetrates the fuel bed is well toward the rear of the stoker.

Ascertaining the temperatures of stationary grate surfaces, such as the tuyères of multiple-retort stokers is not difficult. Individual tuyères or other stationary parts can be drilled and tapped, and soft metal plugs fastened into the cast-iron while the stoker is out of service. Insulated thermocouple wires can then be peened into the plugs and the thermocouple wires brought outside the furnace without their having to be in contact with the moving fuel. Several thermocouples should be used and should be spaced about 10 to 12 in. apart from front to rear. By means of these thermocouples it is possible to determine how far along the grate the fuel travels before ignition penetrates the fuel bed. As such thermocouples are not likely to stand up long under the high temperatures to which they are subjected, readings should be made soon after the fire is put into good operating condition.

The temperatures of traveling- or chain-grate surfaces are also not difficult to ascertain if care is used. The thermocouples must be installed while the grate is in regular operation, or if it is necessary to stop the grate to install thermocouples, the period of shutdown should be very brief. Otherwise, the fire will have burned too low, and abnormal furnace conditions will exist at the time the temperature readings are taken. Attaching the thermocouples to a link of a chain-grate stoker is somewhat more difficult than putting couples on a stoker of the traveling-grate type where an individual finger or key of the grate can be removed and replaced by another while the stoker is in operation. In the case of the link-type stoker, a small hole can be drilled in the forward end of a link, into which can be inserted and peened a soft plug holding the thermocouple wires. The insulated wires must then be carried in the space between two links as each row comes along. Because of the narrow air spaces, it is necessary to separate the links in each row by means of a screwdriver or other such blade in order to place the wires below the grate surface. Wire for this purpose should not be larger than 20 or 21 gage and should be insulated with a light covering of asbestos to protect it from the heat.

In the case of a traveling-grate stoker having removable keys, a key can be prepared with a thermocouple wire and put in place on the stoker while in operation. This is done by removing or breaking out any key, and substituting in its place the key with the thermocouple attached. If the keys of this type of stoker are held on the carrier bars by two lugs, one of these lugs will have to be cut off in order to fit the key down in its proper place on the carrier bar. When the key with the thermocouple is in position, the wires can be kept below the grate surface by separating the keys on each bar as it comes along and pushing the wires downward with a dull blade to prevent abrasion of the insulating covering of the wire.

Effect of Improper Banking

Determining the point of complete penetration of ignition by measuring the grate surface temperature, in addition to serving as a guide for the air supply under the fuel bed, is also of value in determining the cause of burning of grate surfaces. Improper banking of fires is probably the chief cause of burned grates. Very often a fire is banked before the incandescent fuel on the grate is sufficiently burned out. If the air is shut off and the banking started while the end of the fuel bed is very hot, the grate surfaces are almost sure to be burned. This can be shown by placing a few thermocouples in that part of the grate surfaces which will be under the fuel bed when the banking is started. In some instances it has been found that neglect to burn out the fire sufficiently before starting to bank has resulted in grate surfaces being kept at a temperature of around 1200 F for a period of an hour or two. On the other hand, with proper banking the grate surfaces under the bank never reach a temperature higher than about 800 F, and that will exist only for a very brief period.

It has been pointed out that the entire fuel bed depth should be ignited as rapidly as possible. In furnaces where arches are employed, the length and location of an arch governs to a considerable extent the effective burning of a given fuel. By measuring grate temperatures in furnaces having different arch designs, but which burn the same fuel, it has been found that one type of furnace will hasten the penetration and burning of the fuel, while another design may be responsible for slow ignition and a slow burning rate.

Measuring the temperatures of grate surfaces to find the point of complete penetration of ignition is probably the best substitute for the impossible visual study of a cross-section of a burning fuel bed.

THE BTU VALUES OF A COAL*

By J. F. BARKLEY† and L. R. BURDICK‡

The heat contained in a pound of coal may be expressed in one of several ways, namely, "as received," "moisture free," "moisture and ash free," the "H" value, "dry, mineral free," or "moist, mineral free." Determination of these various values and their relation are discussed, examples given, and the results of studies of these values for coals of different rank are included.

THE inherent heating value or the amount of heat that will be produced when a coal is completely burned is measured in British thermal units (Btu) per pound of coal. This standard heat unit is the quantity of heat required to raise the temperature of one pound of water one degree F at about 60 F. The amount of inherent heat is determined by burning a small quantity of the coal in a calorimeter. The exact manner of making this test is standardized by the A.S.T.M.

The value so determined is the total heat developed by complete burning, with all the products of combustion cooled down to the temperature of the calorimeter, which is kept at about room temperature. This total heat is sometimes called the "high" or gross heat value, because it includes the latent heat given up by the water vapor in the products of combustion when the vapor condenses in the calorimeter. The heat as measured is reported as the heat of combustion at constant volume, since the burning is carried out in a tightly closed calorimeter chamber whose volume does not change. In actual use, coal is usually burned in an open-end chamber at constant pressure, generally somewhere near atmospheric. As the heat of combustion at constant pressure is very slightly higher than that at constant volume, it might be considered that the heat at constant pressure should be used as the standard reference base. For an ordinary eastern coal the heat at constant pressure is about 16 Btu per lb higher than that at constant volume. Calorimeter corrections, ordinarily not considered, may amount to about as much. Hence, the value reported is apt to be more nearly the true heating value at constant pressure than at constant volume.

The chemical elements in coal that produce essentially all the heat are carbon, hydrogen and sulphur. Therefore, the Btu value of a coal as shown by the calorimeter may be approximated by computation from Dulong's formula:

$$\text{Btu per lb} = 14{,}544\ C + 62{,}028\left(H - \frac{O}{8}\right) + 4050\ S$$

where C, H, O and S represent the quantities fractions of a pound of carbon, hydrogen, oxygen and sulphur in 1 lb of coal. It is assumed that all oxygen in the coal is combined with hydrogen in the ratio of 8:1 to form water (H_2O); hence, only the remaining uncombined hydrogen is available for producing heat. For anthracite, semi-anthracite and bituminous coals the computed Btu values are usually within $1^1/_2$ per cent of the values determined by the calorimeter. For sub-bituminous and lignitic coals the computed values often deviate as much as 5 per cent.

The several causes for these differences include: (1) The heating values given by the numbers in the formula may not be quite correct for the conditions. (2) All the oxygen may not be combined with hydrogen, as part may be combined with other substances, such as carbon. (3) The percentage of oxygen in coal is determined by subtracting the sum of all the other substances found by analysis from 100 per cent, thus throwing all errors into the percentage of oxygen. (4) The production of heat from coal is not as simple as the formula indicates since various heat reactions occur with other substances in the coal, such as the burning of the iron in the ash. The usefulness of the Dulong formula is quite limited. It is much simpler and cheaper to make a calorimeter test than to analyze for the various chemical elements in the coal. Formulas have been proposed at various times for the calculation of the heating value from the "proximate" analysis which gives the moisture, volatile matter, fixed carbon and ash. Such formulas are apt to give unreliable results.

There are various ways of considering the Btu value of coal. It is ordinarily expressed as the Btu per pound: (1) "as received" or "as sampled," (2) "moisture free" or "dry," (3) "moisture- and ash-free," (4) "H" value, (5) dry, "mineral matter free," (6) moist, "mineral matter free." For any one coal sample, all these values are related by values of the chemical analysis. If the moisture, ash and sulphur contents are known, any one of these values may be calculated from any other.

As-Received and Dry Btu

The as-received or as-sampled Btu is the heat in one pound of coal as found or as ordinarily purchased. The moisture-free or dry Btu value is the heat in one pound after the moisture has been removed by a standardized method in which the coal is dried at a temperature above the boiling point of water, or about 225 F.[1] This drying not only removes the surface moisture that can be seen on the coal (sensible moisture) but also moisture that

* From Bureau of Mines Information Circular 7193, December 1941.

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[1] A.S.T.M., Standard Methods of Laboratory Sampling and Analysis of Coal and Coke (D271-40): A.S.T.M. Standards on Coal and Coke, December 1940, pp. 9-15.

is so closely held by the coal (inherent moisture) that it does not produce wetness. The total moisture varies from time to time for the same coal, being affected by the weather and periods of drying. Although "dry" coal does not really exist except in the laboratory, the dry Btu is a more stable value and is also convenient for comparing different coals. As the moisture has no heat value and merely dilutes the coal, one pound of dry coal would have a higher heating value than one pound of a mixture of the dry coal and moisture. The difference between the two values would vary directly with the amount of moisture. For example, assume a coal "as received" had a Btu of 13,170 per lb and a moisture content of 4.9 per cent. The Btu per pound dry would equal:

$$\frac{13{,}170 \text{ Btu "as received"}}{1.000 - 0.049 = 0.951 \text{ lb}} = 13{,}850 \text{ Btu "dry,"}$$

(dry coal supplying the heat in the mixture)

or

$$13{,}850 \text{ Btu "dry"} \times 0.951 = 13{,}170 \text{ Btu "as received."}$$

Moisture- and Ash-Free Btu

The moisture- and ash-free Btu is the heat in one pound of the coal when not only the moisture but also the ash is removed. Ash as reported from the laboratory is also a diluent and as such supplies no heat. It varies in amount, depending on the mining and cleaning of the coal. The moisture- and ash-free Btu would represent a still more stable value and tend to give the heating value of the "pure" coal substance. If the coal used in the foregoing example had an ash content of 10.0 per cent on the as-received basis $\left(\text{or } \frac{10.0}{0.951} = 10.5 \text{ per cent on the dry basis}\right)$, the moisture- and ash-free Btu would equal:

$$\frac{13{,}170 \text{ Btu "as received"}}{1.00 - (0.049 + 0.10) = 0.851 \text{ lb}} = 15{,}480 \text{ Btu moisture and ash free,}$$

(coal substance free from moisture and ash)

or

$$\frac{13{,}850 \text{ Btu "dry"}}{1.00 - 0.105 = 0.895} = 15{,}480 \text{ Btu moisture and ash free,}$$

or

$$15{,}480 \text{ Btu "moisture and ash free"} \times 0.851 = 13{,}170 \text{ Btu "as received,"}$$

or

$$15{,}480 \text{ Btu "moisture and ash free"} \times 0.895 = 13{,}850 \text{ Btu "dry."}$$

"H" Btu Value

The "H" Btu[2] value of coal was originated to express a heating value of "pure" coal that did not include the heat produced by the sulphur in the coal. It was considered that the heating value of the "pure" coal in a given mine or seam might be fairly constant and that the sulphur was a contamination that had been added in variable amounts to the original coal. The "H" value was derived from the "as-received" or "dry" Btu by first subtracting the heat of the sulphur, taken as 4050 Btu per pound. Assuming the coal used in the preceding example had a sulphur content of 1.9 per cent as received (or 2.0 per cent on the dry basis) then:

$$\frac{13{,}170 \text{ Btu "as received"} - 4050 \times 0.019 \text{ lb (sulphur)}}{1.00 - (0.049 + 0.10 + 0.019) \text{ or } 0.832 \text{ lb (coal substance free from moisture, ash and sulphur)}} = 15{,}740 \text{ Btu "H" value}$$

or

$$\frac{13{,}850 \text{ Btu} - 4050 \times 0.02}{1.00 - (0.105 + 0.02) \text{ or } 0.875} = 15{,}740 \text{ Btu "H" value}$$

Dry, Mineral-Matter-Free Btu

The dry, mineral-matter-free Btu value was later devised to express more nearly the correct Btu value for "pure" coal.[3] Instead of considering the noncoal part to be merely the sum of the moisture, ash and sulphur from the analysis, it was determined as follows:

$$\text{Noncoal} = \text{moisture} + \text{ash} + {}^5/_8\text{S} + 0.08\left(\text{ash} - \frac{10}{8}\text{S}\right)$$

This formula is based upon the fact that the quantity of ash reported in the usual coal analysis is not the true amount of mineral matter as it existed in the coal; it is the residue left after the coal is burned—a step in making the analysis. This burning causes changes in the mineral matter. Before the coal is burned, it is assumed that the sulphur is united with iron to form iron sulphide (FeS_2). While the coal is burning, the sulphur burns to a gas and leaves the ash. The iron, however, unites with oxygen from the air, forming iron oxide (Fe_2O_3) which remains to form part of the ash; therefore, the oxygen increases the weight of the ash. For every pound of sulphur, three-eighths pound of oxygen is added to the ash; therefore, only five-eighths of the sulphur should be added to the ash as weighed to obtain the noncoal substance. The last expression of the formula, $0.08\left(\text{ash} - \frac{10}{8}\text{sulphur}\right)$, is used to approximate the water combined with earthy mineral matter in the coal. Certain forms of mineral matter of the coal, as clay or shale, lose water when heated to the higher temperatures. The weight of this water should also be included in the formula to obtain the true amount of noncoal substance. For every pound of sulphur, ten-eighths pound of iron oxide is formed in the ash. Subtracting ten-eighths sulphur from the ash as weighed, therefore, gives the quantity of earthy material that might have lost water; multiplying this by a chosen figure of 0.08 gives approximately the water lost by the original mineral matter.

The expression,

$$\text{Noncoal} = \text{moisture} + \text{ash} + {}^5/_8\text{S} + 0.08\left(\text{ash} - \frac{10}{8}\text{S}\right)$$

can be simplified by combining:

$$\text{Noncoal} = \text{moisture} + 1.08 \text{ ash} + \frac{21}{40}\text{S (or 0.525 S).}$$

[2] Lord, N. W., and Haas, F., "The Calorific Value of Certain Coals as Determined by the Mahler Calorimeter," *Trans. Am. Inst. Min. Eng.*, **27**, 259 (1897–1898).

[3] Parr, Samuel W., "The Classification of Coal," *Univ. of Illinois Eng. Exper. Sta. Bull. 180*, July 31, 1928.

This expression was further simplified by changing the 0.525 to 0.55, giving the final expression:

$$\text{Noncoal} = \text{moisture} + 1.08 \text{ ash} + 0.55 \text{ S}$$

The dry, mineral-matter-free Btu value is derived from the as-received Btu in a somewhat similar manner to the "H" value.

$$\frac{13{,}170 \text{ Btu (as received)} - 5000 \times 0.019 \text{ lb (S)}}{1.00 - (0.049 + 1.08 \times 0.10 + 0.55 \times 0.019) \text{ or } 0.833 \text{ lb}} = 15{,}700 \text{ Btu dry, mineral matter free}$$

("pure" mineral-matter-free coal substance)

or on the dry basis

$$\frac{13{,}850 - 5000 \times 0.02 \text{ S}}{1.00 - (1.08 \times 0.105 + 0.55 \times 0.02) \text{ or } 0.876} = 15{,}700 \text{ Btu}$$

In these calculations the quantity of heat produced by the sulphur to be subtracted from the calorimetric heat is

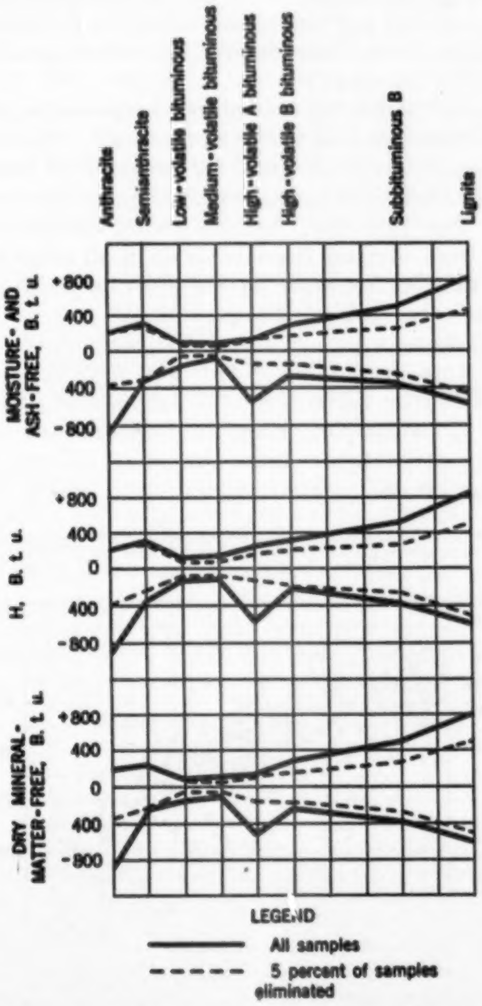


Fig. 1—Range of various Btu values of coal of different rank. The range for each is representative of coal from the same mine

5000 Btu per lb instead of the 4050 Btu used in deriving the "H" value. This change for more accuracy is based on the fact that 4050 Btu is the heat of combustion of pure sulphur and, as already shown, when the sulphur burns the iron with which it is associated also burns, giving some heat not included in the 4050 Btu. The 5000 Btu was chosen as more nearly representing the actual heat produced per pound of sulphur under the conditions in which it occurs in the coal.

Moist, Mineral-Matter-Free Btu

The moist, mineral-matter-free Btu, as the name indicates, is the Btu of one pound of the moist, "pure" coal substance. The value found in coal containing its natural bed moisture but not including visible water on its surface is used in coal-classification standards for determining the rank of certain coals of the bituminous, sub-bituminous and lignitic classes.[4] It may be derived from the as-received Btu as follows:

$$\frac{13{,}170 \text{ Btu (as received)} - 5000 \times 0.019 \text{ lb S}}{1.00 - (1.08 \times 0.10 + 0.55 \times 0.019) \text{ or } 0.882 \text{ lb}} = 14{,}830 \text{ Btu moist, mineral-matter-free}$$

The various Btu values determined in the preceding examples for a coal having, on the as-received basis, a moisture content of 4.9 per cent, an ash content of 10.0 per cent and a sulphur content of 1.9 per cent follow:

As-received or as-sampled Btu	= 13,170
Moisture-free or dry Btu	= 13,850
Moisture- and ash-free Btu	= 15,480
"H" value Btu	= 15,740
Dry, mineral-matter-free Btu	= 15,700
Moist, mineral-matter-free Btu	= 14,830

The range in these figures shows the necessity of defining just what "Btu value" of a coal is being considered.

Constancy of Moisture- and Ash-Free Btu

There is a general belief in the coal trade that the moisture- and ash-free Btu of delivered coal, although varying for coals of different rank, is substantially constant for coal from the same seam, especially for coal from the same mine. If so, calculation of this value from the usual coal analysis and calorimetric Btu value would reveal if a coal did not come from a given area or seam; for restricted areas, it would reveal its probable origin. Knowing the value for a given mine, it would be possible to determine the calorimetric Btu of coal from that mine if the coal analysis were known or the amount of moisture and ash if the calorimetric Btu were known. For example, using the coal of the previous examples:

Coal Analysis, Per Cent

	As Received	Dry
Moisture	4.9	...
Volatile	25.0	26.3
Fixed carbon	60.1	63.2
Ash	10.0	10.5
	100.0	100.0
Btu	13,170	13,850
Moisture- and ash-free Btu	...	15,480

Analysis of Coal From Same Mine, Per Cent

	As Received	Dry
Moisture	3.6	...
Volatile	25.9	26.9
Fixed carbon	62.5	64.8
Ash	8.0	8.3
	100.0	100.0

[4] A.S.T.M., Standard Specifications for Classification of Coals by Rank (D388-38): A.S.T.M. Standards on Coal and Coke, December 1940, pp. 83-88.

On the as-received basis, the amount of moisture- and ash-free coal per pound of coal as received equals $1.00 - (\overset{\text{Moisture}}{0.036} + \overset{\text{Ash}}{0.08})$ or 0.884 lb.

$$15{,}480 \text{ (moisture- and ash-free Btu per pound, the constant for that mine)} \times 0.884 = 13{,}680 \text{ Btu as received}$$

On the dry basis:

$$15{,}480 \times (1.00 - 0.083) \text{ or } 0.917 = 14{,}200 \text{ Btu dry}$$

If the as-received Btu were known, the quantity of moisture and ash would be:

$$\frac{13{,}680}{15{,}480} = 0.884 \text{ lb}$$

$1.00 - 0.884 = 0.116$ lb per pound of coal; that is, the sum of the ash and moisture in per cent would be 11.6 per cent. On the dry basis:

$$\frac{14{,}200}{15{,}480} = 0.917 \text{ lb}$$

$$1.00 - 0.917 = 0.083 \text{ lb, or } 8.3 \text{ per cent ash}$$

To determine the possible limitations or the accuracy of the idea of a constant moisture- and ash-free Btu, a study was made of many delivered coal analyses from the laboratories of the Bureau of Mines.[5] As the characteristics of coal from a given seam differ somewhat in different areas, it was considered that samples from the same mine would vary least in value. Thirteen mines were therefore chosen covering coals of many ranks, as shown in Table 1.

Results

Studies were made not only of the moisture- and ash-free Btu but also of the "H" value and the dry, mineral-matter-free Btu. Fig. 1 shows the range of the various Btu values of coals of different rank, each rank being representative of coal from the same mine. The dotted lines indicate the range after eliminating a number of values farthest from the average; the number of values eliminated was arbitrarily chosen as 5 per cent of the total number in each instance. In general, the range is about the same for the three ways of expressing Btu values. The simpler, moisture- and ash-free value appears to serve as well as any other for most Btu calculations.

TABLE 1—TYPICAL ANALYSES OF COALS STUDIED

			Coal Analysis		Dry basis			
Mine	State	Rank	H_2O	Vol.	F. C.	Ash	S	Btu
1	Pa.	Anth.	4.5	4.8	84.6	10.6	0.7	13,430
2	Pa.	Anth.	2.2	7.2	80.7	12.1	1.1	13,400
3	Va.	Semi-anth.	1.2	12.4	64.9	22.7	0.5	11,660
4	Pa.	Low-vol. bit.	2.7	16.7	74.4	8.9	1.3	14,250
5	Pa.	Low-vol. bit.	3.6	18.2	74.4	7.4	0.9	14,500
6	W. Va.	Low-vol. bit.	3.0	20.4	75.3	4.3	0.9	14,980
7	Pa.	Medium-vol. bit.	2.6	22.2	70.4	7.4	1.8	14,500
8	Pa.	Medium-vol. bit.	2.2	26.2	65.0	8.8	2.3	14,190
9	Ky.	High-vol. A bit.	3.5	36.2	49.1	14.7	4.4	12,540
10	W. Va.	High-vol. A bit.	1.6	36.3	55.2	8.5	3.1	13,940
11	Ill.	High-vol. B bit.	8.9	39.3	50.5	10.2	3.7	12,880
12	Wyo.	Sub-bit. B	20.2	41.2	53.4	5.4	0.6	12,370
13	N. Dak.	Lignite	31.5	38.4	47.9	13.7	1.1	10,600

Although the range in moisture- and ash-free values is rather large, particularly for the anthracites, the subbituminous coal and the lignite, about 55 to 70 per cent of the values for the bituminous coals, fell within about 25 to 60 Btu of the average.

For some estimating and survey purposes the average and moisture-free Btu value is of interest. Such values were compiled and tabulated for various coal seams and areas, together with the corresponding dry, mineral-matter-free Btu and dry, volatile-matter values. These values[6] were derived from analyses of all mine and delivered samples recorded by the Bureau of Mines and also from other published analyses.

Fig. 2 shows a plot of the dry volatile matter versus the moisture- and ash-free Btu and also the mineral-matter-free Btu, taken from the tabulations mentioned above. A similar plot, using the moisture- and ash-free volatile matter, taken from the same source, gave a somewhat greater "scatter" effect.

[5] For complete study, results and mathematical development see Barkley, J. F., and Burdick, L. R., "Constancy of Btu Value of 'Pure' Coal," *Bureau of Mines Rept. of Investigations 3572*, 1941, 10 pp.

[6] Because of space limitations these voluminous tabulations are not here reproduced, although contained in Information Circular 7193.

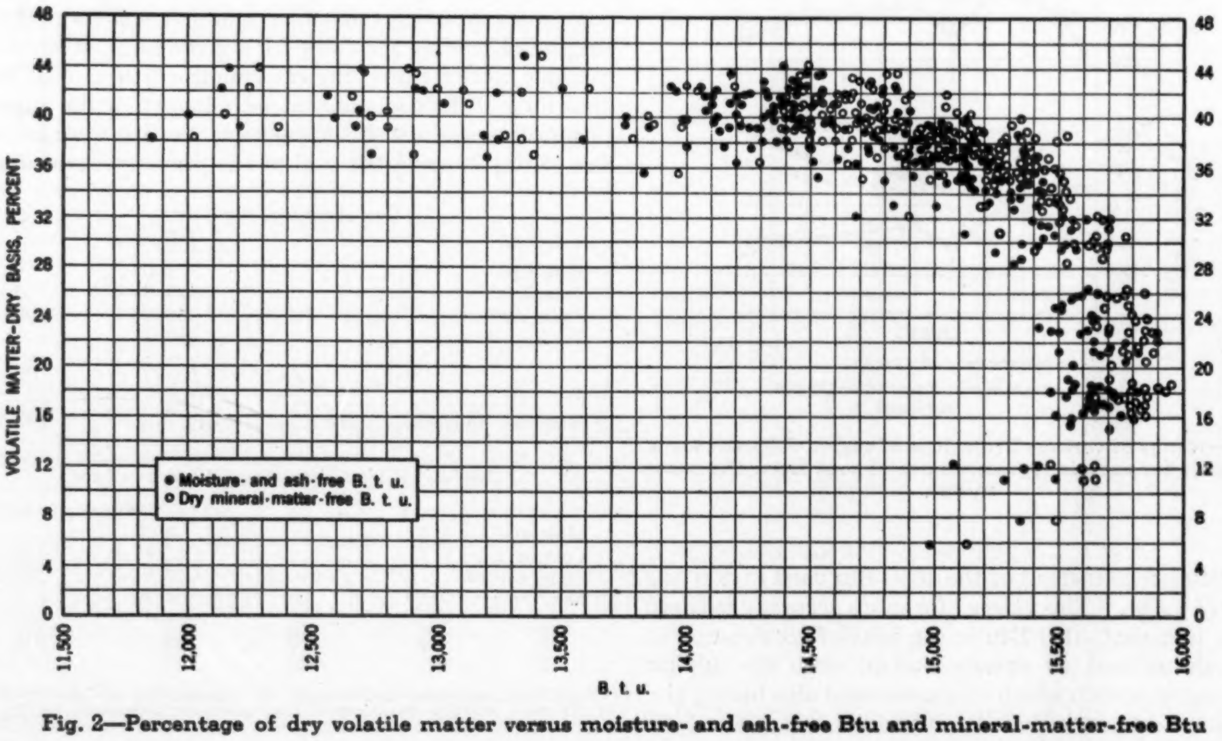


Fig. 2—Percentage of dry volatile matter versus moisture- and ash-free Btu and mineral-matter-free Btu

Textile Finisher Adds Large Unit

By J. C. PORTER

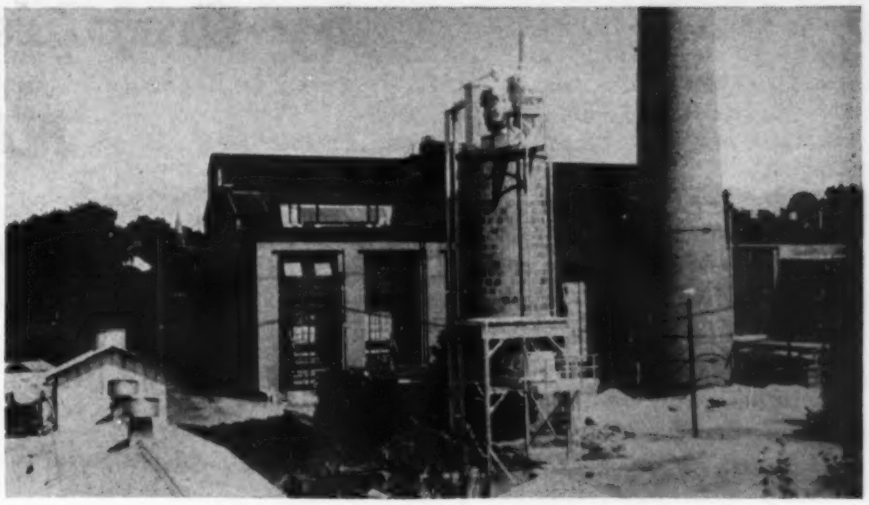


Fig. 1—General view of completed addition

IN 1929 the Rock Hill Printing & Finishing Company at Rock Hill, S. C., started operation of what was to become one of the largest textile finishing plants in the country. The power plant consisted of three 450-hp Stirling boilers, fired with underfeed stokers, and one 1500-kva turbine-generator. Feedwater, about sixty per cent makeup and forty per cent returns, was heated in a contact heater and fed to the boilers at 245 F. Steam was generated at 250-lb gage and 100 deg superheat. A large amount of the total live steam produced and all of the exhaust steam was, and still is, used in processing.

Growth of the plant made it necessary to add to the power house equipment from time to time until by the summer of 1940 the equipment consisted of

Three 450-hp boilers (original)
One 550-hp boiler
Two 770-hp boilers
Two 250-hp hrt boilers
One 1500-kva turbine-generator (original)
One 2000-kva turbine-generator

Even casual studies at that time indicated that this equipment would not be able to handle the plant production under winter conditions; hence surveys were undertaken. It was decided to repair the existing boilers, and install an economizer, a water heater, a new feed pump and hotwell pumps, as quickly as possible. These improvements were started immediately and further studies made as to the advisability of purchasing an additional boiler. All things considered, it was felt by those concerned that pulverized coal had a slight edge over stoker firing for this installation.

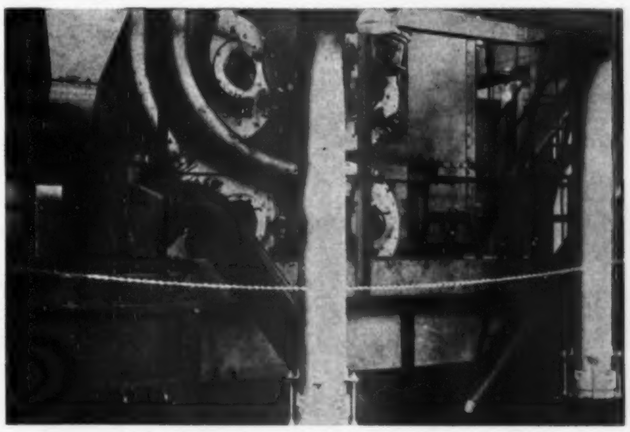


Fig. 2—Boiler front and pulverizers

When the final figures showed that the plant could better afford to operate with a new unit, the requirements were put in the hands of the boiler manufacturers. The final choice was based on space limitations, cost, appearance, performance and delivery of comparable units, after many miles had been traveled and many plants had been visited to make comparisons and talk with operators. The unit finally decided upon was a Combustion Engineering Co. type VU two-drum steam generator having a capacity of 150,000 lb per hr of saturated steam at 250 lb pressure. This unit is fired by two Raymond Bowl mills, each serving two burners. Draft is supplied by Clarage induced- and forced-draft fans and air for combustion is heated in a Ljungstrom regenerative-type air preheater.

Although somewhat unusual for an installation of this kind, all the auxiliaries are turbine-driven. While the principal reason for this was that they are thus independent of power failures, other strong considerations were that electric generator capacity is limited whereas live steam bled to back pressure is high; also turbine fan drives are more economically controlled than are motor drives, and it was felt that average power plant operators will take better care of turbines than of motors. A dual drive is being considered for one pulverizer.

As all the steam generated in this unit during normal operation is used in processing, no superheater was installed. In determining the size of furnace and mills, all coals economically available to this section were considered and the equipment designed to burn any of them. This gives a unit which will handle successfully any coal having a volatile of about 30 per cent or more, a grindability of 46 Hardgrove and an ash-fusion temperature above 2200 F.

To date after four months' operation, no conditions have arisen which indicate any fundamental error in design or engineering. Performance has been satisfactory, and savings are as much as could be expected. These savings, incidentally, were based on the installation not only of a boiler, but of labor saving coal- and ash-handling equipment.

Combustion Calculations by Graphical Methods—NATURAL GAS

By A. L. NICOLAI

Combustion Engineering Co., Inc.

The fourth of a series each dealing with a particular fuel, by which, through the use of charts, combustion calculations can be quickly and accurately made. The first article, which appeared in the August issue, dealt with fuel oil; the second, in October, with coke-oven gas; and the third with blast-furnace gas. The next article of the series which is scheduled for April will start solid fuels.

NATURAL gas is a fuel that is chiefly found in sandstone formations of loose texture and in shale seams or cavities. Unlike coke-oven and blast-furnace gas, it is the product of the disintegration of organic matter trapped in the rock over long periods of time, rather than the result of a man-made process. To the miner it is also known as "fire damp" and to lowland dwellers as "marsh gas."

Natural gas fields frequently exist in the neighborhood of oil deposits. This is illustrated by Fig. 1,[1] where it is seen that natural gas occupies the space on top of the oil and that oil in turn lies over salt water. The relative density of these substances accounts for their segregation, natural gas being lightest, water heaviest and oil in between. However, not all natural gas is associated with oil. At times it is found by itself, or directly in contact with salt water, hermetically sealed by the rock and under very high pressures.

The characteristics of natural gas, as it comes out of the earth's surface, depend to some extent on its underground conditions. It is generally odorless and colorless. It burns with a blue flame and is highly explosive when mixed with air in the correct proportions. The range in its chemical composition is indicated by Table 1, where it is seen that methane, CH_4, and ethane, C_2H_6, are its principal combustible components. This is due to the fact that in natural gas analyses it is customary to report the heavier hydrocarbons in terms of CH_4 and C_2H_6, or, if this grouping is not satisfactory, in terms of C_2H_6 and C_3H_8 (propane).

If the natural gas has been in contact with oil, it will be impregnated with varying amounts of heavy hydro-

[1] From *Technical Paper 325*, U. S. Dept. of Interior.

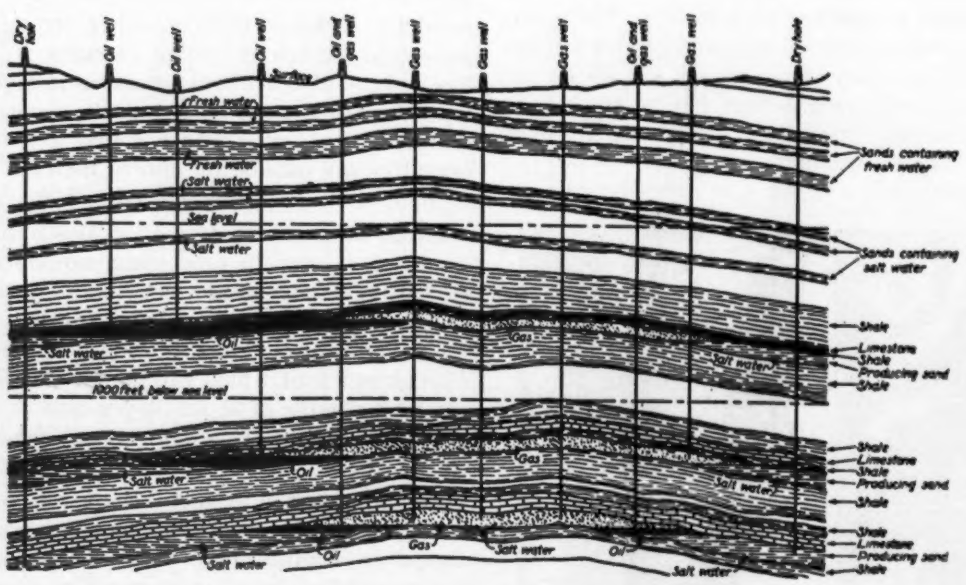


Fig. 1—Generalized section through an oil and gas field

carbon vapors, such as pentane, C_5H_{12}, and hexane, C_6H_{14}, which are liquid at ordinary pressure and temperature. This is then known as "wet" natural gas, and it is usually economical to dry it by liquefying the heavy vapors, which are then collected and called casing-head gasoline. In a complete chemical analysis of natural gas, a certain fraction of a heavy hydrocarbon is sometimes preceded by the letter "n," such as "n-butane," which means "normal" butane, and the remainder uses the prefix "iso," meaning "equal," as, for example, "iso-butane." The chemical formula is the same in both cases as the prefix merely denotes a different arrangement of the atoms in the hydrocarbon molecule, but the physical and chemical properties of these so-called "isomerics" are not usually the same.

"Dry" natural gas comes from wells away from oil deposits and is, therefore, comparatively devoid of heavy hydrocarbons. Dry gas has generally less than one gallon of gasoline per 1000 cu ft of gas, and is found in nature under pressures sometimes as high as 2000 lb per sq in.

Dust.—As generally defined by fuel analysts, the term "dust" includes any solid substance which is light enough to be carried in suspension by a gas. The dust in natural gas consists mainly of sand from the gas-producing well and dirt which may accidentally be picked up by the conveying equipment. Dust catchers are sometimes used, but in general the dust concentration is low enough to be disregarded. For combustion calculation purposes, the author believes that the quantity of dust in natural gas may be safely neglected, particularly when the gas is delivered at the end of a long pipe line where the dust has had a chance to settle out in pipe turns and compressor valves.

Temperature.—The temperature of natural gas as it issues from the ground is dependent on the depth of the well and may vary from 32 F to 165 F. The general rule among geologists is to assume an increase in temperature of 1 deg F for every fifty feet in depth,[2] although this rule will not always check with actual measurements taken in the field.

TABLE 1—CHARACTERISTICS OF TYPICAL NATURAL GASES

CO_2	N_2	H_2S	CH_4	C_2H_6	C_3H_8	C_4H_{10}	C_5H_{12}	Density Lb/Cu Ft	Heat Value Btu/Cu Ft High	Heat Value Btu/Cu Ft Low	Heat Value Btu per Lb High	Heat Value Btu per Lb Low	Atmos. Air at Zero Excess Air, Lb/10^6 Btu	CO_2 at Zero Excess Air, %
5.50	...	7.00	77.73	5.56	2.40	1.18	0.63*	0.05553	1030	934	18550	16840	739	12.1
3.51	32.00	0.50	52.54	3.77	2.22	2.02	3.44*	0.06527	841	765	12880	11720	741	12.4
26.2	0.7	...	59.2	13.9	...	...	...	0.06654	826	747	12420	11230	733	15.2
0.17	87.69	...	10.50	1.64	...	...	...	0.07053	132	120	1872	1703	732	6.9
0.20	0.60	...	99.20	...	...	...	...	0.04257	983	887	23100	20850	732	11.7
...	0.60	...	...	79.40	20.00	...	...	0.08604	1851	1696	21550	19730	739	13.4
...	0.50	...	...	21.80	77.70	...	...	0.10669	2276	2094	21350	19660	740	13.6

* All hydrocarbons heavier than C_5H_{12} were assumed to be C_5H_{12} for combustion calculations.

From the standpoint of combustion calculations, it is important to remember that the terms "dry" or "wet" as commonly applied to natural gas refer to its gasoline vapor, and not to its moisture content. In fact, the only time natural gas has any moisture in it at its point of origin is when it is next to salt water. But this is a relatively unusual occurrence.

When sulphur is present in the oil deposit, the analysis of natural gas associated with this oil often includes hydrogen sulphide. This hydrogen sulphide is removed in most instances before distributing the gas because it is a potential source of corrosion in the pipe lines.

Other Constituents in Natural Gas

In addition to the combustible constituents just discussed, Table 1 shows that natural gas may contain considerable amounts of carbon dioxide, CO_2, as in the California fields, or nitrogen, N_2, as in certain Kansas and Oklahoma fields. It sometimes happens that gas is drawn from wells under suction and that, because of this, air will leak into the lines. The analysis of natural gas will then show the presence of oxygen.

Whenever possible, natural gas is delivered at the required destination under well pressure. But it is also frequently transported over long distances by means of pipe lines and compressors. Thus, the furnace which uses this gas may be close to the well or at the end of a pipe line and the conditions in the pipe lines may be such as to change the composition of natural gas going to the furnace. For instance, aside from the effect of compression, which liquefies the heavy members of the hydrocarbon family, water and oil are sometimes sprayed into the gas to keep it "moist." Evidently, any natural gas analysis, as fired, should be taken at the point of use rather than at the well.

It is also apparent that gas which has flowed through many miles of pipe line will have whatever ambient temperature that prevails in the locality where it is burned; most probably from 40 F to 80 F. In combustion calculations for natural gas it is deemed sufficiently accurate to assume the standard 62 F, when its actual temperature is not reported.

Moisture.—As already noted, the only time that natural gas can be reasonably expected to have any moisture on leaving a well is when it previously has lain in contact with salt water. It may then be considered saturated with moisture at whatever temperature it had in the well.

However, gas which is delivered from a pipe line has often been "rehydrated," that is, saturated with water vapor by means of steam jets in order to lower the cost of maintaining pipe gaskets. Since the steam is ordinarily added to the gas in the high-pressure line, when the pressure is lowered for local distribution the relative humidity of natural gas will also drop. Still another complication is introduced when a wet displacement meter is employed to measure the gas consumption. In this meter the gas may be long enough in contact with the water to become saturated with it.

In view of the variable and uncertain moisture content in natural gas, and in the absence of more definite determinations, the author believes that it will be conservative, especially from the viewpoint of the designer, to assume natural gas to be saturated at 62 F and 30 in. Hg.

Density.—The method given in the article on blast-furnace gas[3] is equally applicable for finding the density of natural gas. Likewise, Figs. 2 and 3 and equation (11)

[2] Bulletin No. 17, Kansas City Testing Laboratory.
[3] COMBUSTION, December 1941.

of that article may be used whenever it is desired to correct for a temperature and moisture content higher than saturation at 62 F. Before going to a great deal of refinement, however, it must be remembered that the gas calculated density can be no more accurate than the volumetric analysis from which it is derived. A natural gas analysis which groups all hydrocarbons as CH_4 and C_2H_6, or C_2H_6 and C_3H_8, may indicate a lower density than the actual value.

Heating Value.—As with all other gaseous fuels, it is customary to compute the high heating value of natural gas, in Btu per cu ft at 62 F, by adding together the heat evolved by the combustible components reported in the gas analysis. Thus, for a gas such as the first one in Table 1, the procedure indicated in Table 2 may be employed:

TABLE 2

	Per Cent, by Volume, Dry	Volume Cu Ft per Cu Ft of Gas		Heating Value, Btu per Cu Ft Saturated at 62 F*		Heat Evolved by Components Btu/Cu Ft
Hydrogen sulphide, H_2S	7.00	0.0700	×	617	=	43
Methane, CH_4	77.73	0.7773	×	991	=	770
Ethane, C_2H_6	5.56	0.0556	×	1715	=	95
Propane, C_3H_8	2.40	0.0240	×	2451	=	59
Butane, C_4H_{10}	1.18	0.0118	×	3182	=	38
Pentane, C_5H_{12}	0.63	0.0063	×	3903	=	25
Heating Value of Gas Saturated with Moisture at 62 F					=	1030 Btu/Cu Ft

* See COMBUSTION, October 1941 p. 39.

The high heating value in Btu per pound is then obtained by dividing the Btu per cubic foot by the density at 62 F and 30 in. Hg. To correct the Btu per pound for the effect of higher temperature and moisture content, it is necessary to refer to Fig. 4 and equation (12) of the article on blast-furnace gas.[3]

The Btu per cubic foot calculated by the foregoing method will generally be lower than that determined by calorimeter because of the arbitrary grouping of hydrocarbons explained before. For the same reason the calculated density will also be lower than actual. It follows that the Btu per pound, with which we are primarily concerned, is nearer to its actual value when it is figured from the "calculated" Btu per cubic foot and "calculated" density than when it is the ratio of the "calorimeter" Btu per cubic foot and the "calculated" density of the gas.

Fuel in Products, F.—After determining the Btu per pound (*HHV*), *F*, which is that portion of the fuel, in pounds per million Btu fired, that reappears in the products of combustion, is easily read from Fig. 1 of the first of these articles on combustion calculations.[4]

Atmospheric Air, A.—The atmospheric air in pounds per million Btu as fired may be taken from Curve A of Fig. 3, of the present article, for any value of excess air up to 70 per cent. As previously defined, the term "atmospheric air" is used to designate air which contains 0.013 pound of water vapor per pound of dry air, an arbitrary amount equivalent to 60 per cent relative humidity at 80 F. The atmospheric air, *A*, may be corrected for temperatures higher than 62 F in accordance with equation (13) of the December 1941 article in COMBUSTION.

No chemical analysis of natural gas is necessary in obtaining the atmospheric air from Curve A.

Total Products, P.—The weight of the products of combustion in pounds per million Btu as fired is given by $P = F + CA$, where C is a factor to correct A for the combustible loss due to imperfect combustion of the fuel. Natural gas being one of the most easily burned of fuels, C is assumed to be 1 for any properly designed furnace supplied with the correct amount of excess air.

Moisture From Fuel, W_f.—W_f is the sum of W_s, the water vapor required to saturate the fuel; W_e, the entrained moisture; and w_h, the water formed in burning the hydrogen compounds in the fuel.

For any gaseous fuel containing w_s pound of water vapor per pound of dry fuel, the pounds of water vapor per million Btu as fired are given by

$$W_s = \frac{w_s(1 - w_s)10^6}{HHV} \tag{17}$$

where *HHV* is the high heating value of the gas in Btu per pound as fired. Fig. 2 of the present article is a convenient plot of equation (17).

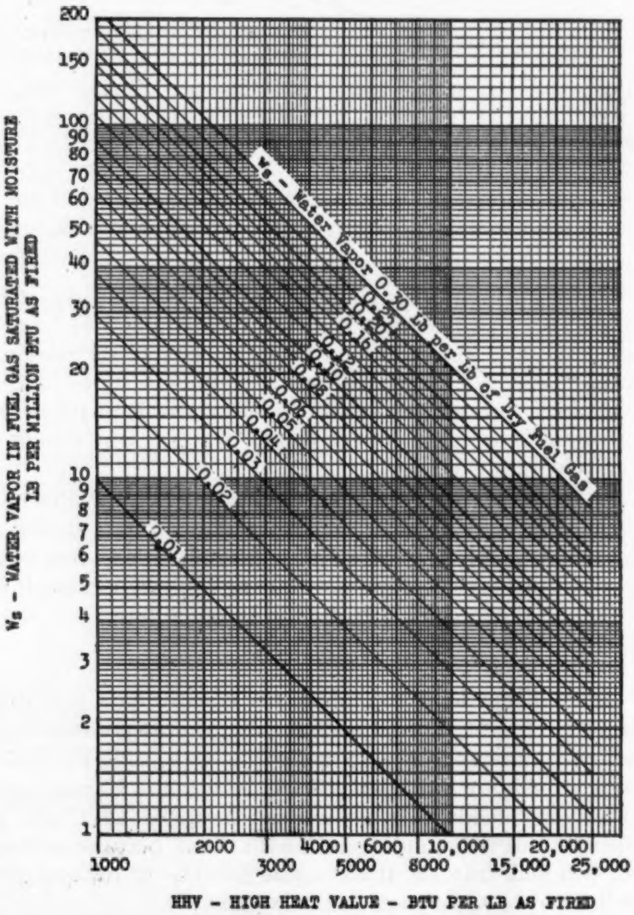


Fig. 2—Water vapor in fuel gas

From the preceding discussion, it is apparent that no entrained moisture is present in natural gas.

The water produced by the combustion of natural gas is given by

$$W_h = \frac{46{,}700(H_2S + 2CH_4 + 3C_2H_6 + 4C_3H_8 + 5C_4H_{10} + 6C_5H_{12})}{\text{Btu per cu ft at 62 F and 30 in. Hg}} \tag{18}$$

For natural gas saturated with moisture at 62 F, W_h may be conveniently read from Curves B of the accom-

[4] COMBUSTION, August 1941.

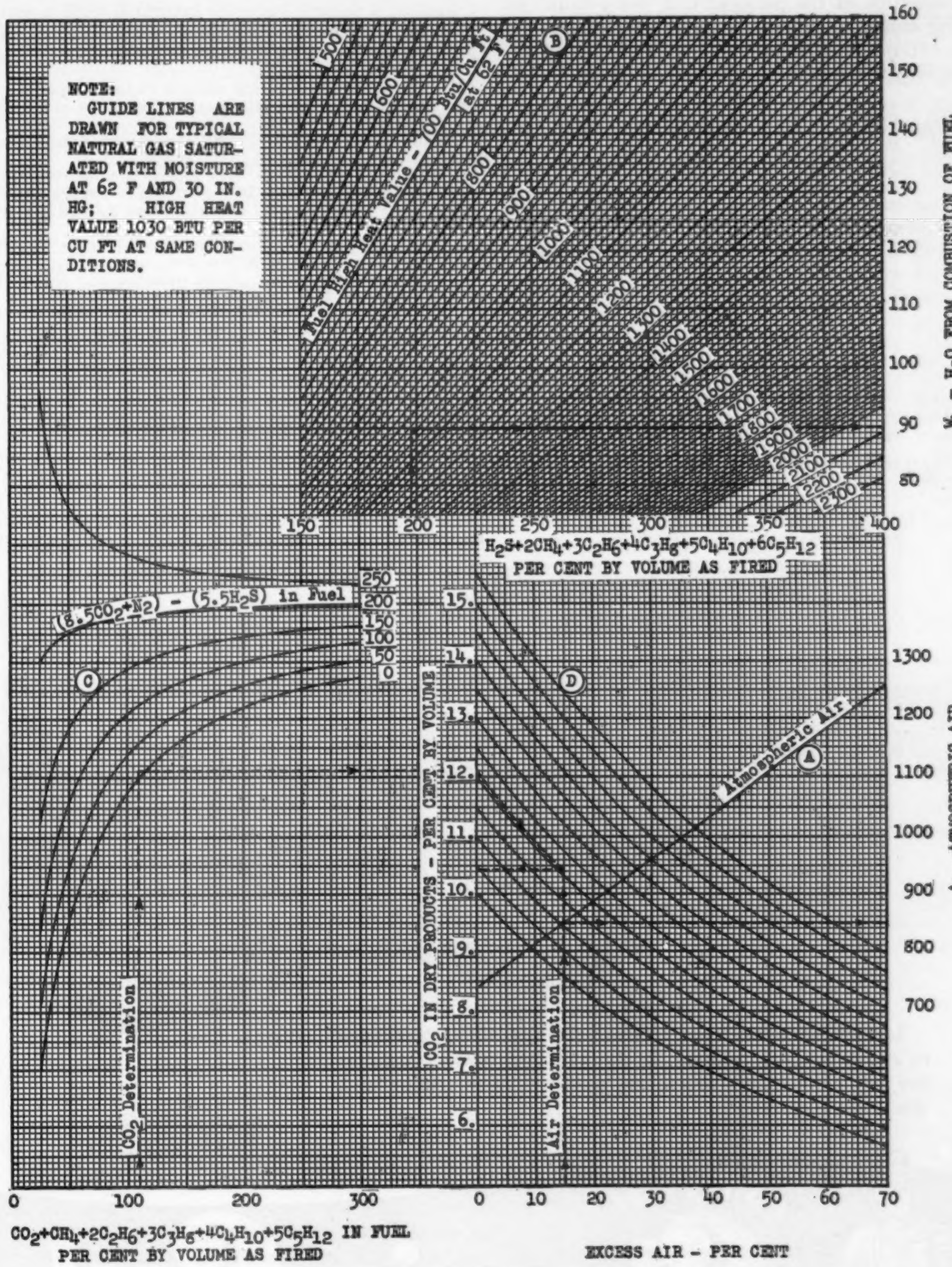


Fig. 3—Chart for natural gas

panying Fig. 3. When it is desired to correct W_h for higher temperature and moisture content, equation (15)[3] may be used.

Per Cent CO_2 in Products.—Curves C, Fig. 3, permit the determination of the per cent CO_2 (by volume) in the dry products of combustion for zero excess air. They are nothing more than a plot of the following approximate equation:

Per cent CO_2 (at zero excess air) =

$$\frac{100}{6.64 + \dfrac{188 + 0.88(5.5H_2S - 8.5CO_2 - N_2)}{CO_2 + CH_4 + 2C_2H_6 + 3C_3H_8 + 4C_4H_{10} + 5C_5H_{12}}} \qquad (19)$$

Then, by means of guide lines D, the per cent CO_2 for any other excess air up to 70 per cent may be read. However, the author does not advise the use of Curves D for natural gases with a nitrogen percentage of over 40, especially at high values of excess air.

CORRECTION: In the article, "Combustion Calculations by Graphical Methods—Coke-Oven Gas," in the October 1941 issue of COMBUSTION, equation (10) should be corrected to read:

Per cent CO_2 (at zero excess air) =

$$\frac{100}{1 + \dfrac{0.713 \times \text{Btu per cu ft at 62 F and 30 in. Hg}}{(100 + C_2H_4 + 5C_6H_6) - (H_2 + N_2)}}$$

Natural Gas

(See Chart on Page 41)

EXAMPLE

Assume a natural gas to be saturated with moisture at 62 F to have the typical analysis listed first in Table 1 and to be burned with 15 per cent excess air. Then

1. *Fuel, F.* For a high heat value of 18,550 Btu per lb, refer to Fig. 1 of the August 1941 article in COMBUSTION and from it read F = 54 lb per million Btu.
2. *Atmospheric Air, A.* From Curve A, Fig. 3, for 15 per cent excess air read A = 850 lb per million Btu.
3. *Unburned Combustible.* The general assumption when burning natural gas in stationary boiler furnaces is that the combustible loss is zero. Consequently, C in equations (3) and (4)[4] may be taken as 1.
4. *Total Products, P.* From equation (4),[4] $P = F + CA = 54 + 1 \times 850 = 904$ lb per million Btu.
5. *Moisture in Air, W_a.* From equation (5),[4] $W_a = 0.013A = 0.013 \times 850 = 11$ lb per million Btu.
6. *Moisture From Fuel, W_f.* Since W_e, the entrained moisture, is zero and W_s, the saturation moisture, is negligible, from Curves B, Fig. 3, for a high heating value of 1030 Btu per cu ft and $H_2S + 2CH_4 + 3C_2H_6 + 4C_3H_8 + 5C_4H_{10} + 6C_5H_{12} = 7.0 + 155.5 + 16.7 + 9.6 + 5.9 + 3.8 = 198.5$ per cent by volume, read $W_f = W_h = 90$ lb per million Btu.
7. *Dry Gas, P_d.* From equation (7),[4] $P_d = P - (W_a + W_f) = 904 - (11 + 90) = 803$ lb per million Btu.
8. *Per Cent CO_2 in Products.* For $CO_2 + CH_4 + 2C_2H_6 + 3C_3H_8 + 4C_4H_{10} + 5C_5H_{12} = 5.5 + 77.7 + 11.1 + 7.2 + 4.7 + 3.2 = 109.4$ per cent by volume and $8.5\ CO_2 + N_2 - 5.5H_2S = 46.7 + 0 - 38.5 = 8.2$ per cent by volume, from Curves C, Fig. 3, read 12.1 per cent CO_2 at zero excess air. Following Curves D as guide lines to 15 per cent excess air, read $CO_2 = 10.4$ per cent.

1942 Midwest Power Conference

The next annual meeting of the Midwest Power Conference will be held on April 9–10 at the Palmer House, Chicago. This Conference, as in the past, is sponsored by the Illinois Institute of Technology with the cooperation of nine other midwestern universities and colleges and the local sections of the Founder and other engineering societies.

The directorate of the Conference, cognizant of the fact that the need in the present war effort is power, and even more power, is doing its utmost to provide a program for this annual meeting which will not only uphold the tradition of the Conference but will also provide a stimulus in the present emergency.

The preliminary program of the Conference will contain, in addition to the opening meeting, sessions on electric power transmission, industrial power plants, hydro power, fuels and combustion, diesel power and central station practice. The last mentioned is sponsored by the Chicago Section of the A.S.M.E. and all arrangements for it are being made by the section's chairman of its Power and Fuels Division, J. R. Michel. In addition to these sessions, the Conference program will include two joint luncheons, one with the Chicago Section of the A.S.M.E. and the other with the Chicago Section of the A.I.E.E. A high light will be its All-Engineers Dinner on the evening of April 9.

The Conference will be opened by President H. T. Heald of the Illinois Institute of Technology and Dr. A. A. Potter, Dean of Engineering of Purdue University. Among the papers and speakers will be the following:

- "Boiler Circulation Problems," by A. A. Markson.
- "Recent Field Experience With Natural Lightning," by C. F. Wagner, Manager Central Station Engineering, Westinghouse Electric & Mfg. Co.
- "Lightning Proof Line Design," by A. C. Monteith, Manager Industry Engineering Department, Westinghouse Electric & Mfg. Co.
- "Power in the Flour Milling Industry," by A. R. Ulstrom, Cereal Engineering and Construction Co., Minneapolis.
- "Feedwater Treatment in Small Power Plants," by E. P. Partridge, Director of Research, Hall Laboratories, Inc.
- "Construction and Erection of the New High-Pressure Unit of the Montaup Electric Co.," by F. H. Rosencrantz, Vice-President, Combustion Engineering Co.
- "Silting of Water-Power Reservoir," by Professor E. W. Lane, Iowa Institute of Hydraulic Research.
- "Power Recovery Installation at the Aviation Engine Plant of Buick Motors," by C. A. Chayne, Chief Engineer, Buick Motor Division, General Motors Corporation.
- "Preventing and Extinguishing Electrical Oil Fires," by H. W. Eales, Chief Electrical Engineer, Public Utility Engineering and Service Corporation, Chicago.
- "Radial Diesels," by Professor E. T. Vincent, University of Michigan.
- "Results Obtained by Spreader Stokers With Continuous Ash Discharge," by R. N. Bucks, Supt. of Power Plants, The Studebaker Corporation.

Removing Oil From Condensate

With reference to the article under the subject title on page 46 of COMBUSTION for January 1942, I am greatly alarmed by the last paragraph which sets forth a "rule-of-thumb" test to determine the presence of oil in boiler feedwater and particularly by the last sentence which states "If, on the other hand, such globules do not appear it can be concluded that the water is free of oil, or the amount is so small as not to require special attention."

The standard "condition" stipulated by the A.B.M.A. with regard to oil contamination is stated as follows:

> "WATER: The total quantity of oil or grease, or substances which are extractable either by sulphuric ether or by chloroform shall not exceed 7 ppm in the boiler water when the sample being tested is acidified to 1 per cent hydrochloric acid, or 7 ppm in the feedwater when the sample being tested is first concentrated at low temperature and pressure to the same ppm total solids as the boiler water."

In consideration of the fact that the average number of concentrations of feedwater in the boiler is at least 10, and in many instances much higher, this allows for 0.7 ppm of oil, grease or extractable matter in the boiler feedwater and we very seriously question the ability of even the most expert laboratory technician to detect even somewhat greater quantities of oil in boiler feedwater by means of the "rule-of-thumb" test suggested.

When further consideration is given to the desirability and probability of the presence of sodium alkalinity by deliberate application in boiler feedwater, or to the presence of such alkalinity in condensate which we sometimes find present though previously undetected and caused basically by oil contamination of the boiler feedwater, and the presence of considerable quantities of readily saponified animal and vegetable oils in modern lubricants, the "rule-of-thumb" procedure is further condemned.

In numerous instances we have experienced some difficulty in convincing plant operators of the responsibility of considerable quantities of oil contamination for detrimental steam quality because they "could not see any traces of oil." We know that this experience is common to boiler manufacturers and that you are aware that oil contamination of boiler feedwater is an extremely serious operating hazard.

The standard procedure for the determination of oil contamination is as follows:

Quantitative Test for Oil

Equipment:
- C.P. nitric acid.
- C.P. carbon tetrachloride.
- Separatory funnel—preferably 500 cc.

NOTE: No grease is used on stopcock of separatory funnel.

Procedure:

1. Use 250 cc water (unfiltered—as

drawn) and acidify with 5.0 cc concentrated nitric acid, in a separatory funnel.

2. Add 25 cc carbon tetrachloride (C.P. or oil-free material) and mix with caution.

3. Draw off carbon tetrachloride and add a few pieces of stick or pellet caustic. (C.P. sticks of fused calcium chloride are preferable to caustic.) Stir occasionally.

4. Add a second 25-cc portion of carbon tetrachloride to the water, mix by shaking, draw off and add to first carbon tetrachloride extraction.

5. After one-half hour, filter carbon tetrachloride extraction into a small weighed flask and evaporate slowly, finishing if possible in oven at 105 C.

6. Cool and weigh, and increase of weight in milligrams × 4.0 gives ppm total oil.

7. Parts per million divided by 17 gives grains per gallon.

H. E. Cable, *Acting Manager*
Aluminate Chemicals Limited

Average Coal Costs and Prices

The Bituminous Coal Division of the Department of the Interior has issued preliminary mine realization figures covering average prices which the coal-producing industry received during its first year of market stabilization under the present set-up of the Bituminous Coal Act. The figures indicate that producers sold their coal at an average price of $2.13 per ton which was 12 cents per ton above the established minimum.

NEW CATALOGS AND BULLETINS

Any of these publications will be sent on request

Corrosion in Water Circuits

Wallace & Tiernan Products, Inc., has issued a 22-page booklet entitled "Microbiological Deposits in Cooling Water Circuits" which presents an outline and discussion of theories offering an explanation for some types of corrosion in water circuits. The biological approach is emphasized and illustrative references to contemporary use of chlorination for microbiological growths are included. This bulletin is admirably printed and generously illustrated with photomicrographs and other illustrations.

CO_2 Recording Equipment

Recent improvements in Micromax CO_2 recording equipment are described in a revised 16-page bulletin issued by the Leeds & Northrup Company. A feature of the new equipment is that the flue-gas sample comes in contact only with glass from the time it leaves the stack until it is automatically analyzed. Illustrations include installation and wiring diagrams, halftone reproductions of instruments and installations and full-size reproductions (in color) of round and strip-chart records.

Heat Insulation

The Ehret Magnesia Manufacturing Company has issued a new "Heat Insulation Handbook" which presents in a compact form a wealth of data on heat insulation and the company's line of related products. The first part of the book comprises more than 100 pages devoted to short informative articles dealing with the nature and application of insulating materials, together with efficiency tabulations; the second part comprises about 70 pages giving recommendations regarding materials and methods of application to boilers, power equipment, heating, piping, air conditioning, and refrigeration, and also useful tables pertaining thereto. The book is admirably illustrated, size $5^3/_4 \times 7^1/_4$, and is nominally priced at $1.

Variable Speed Control

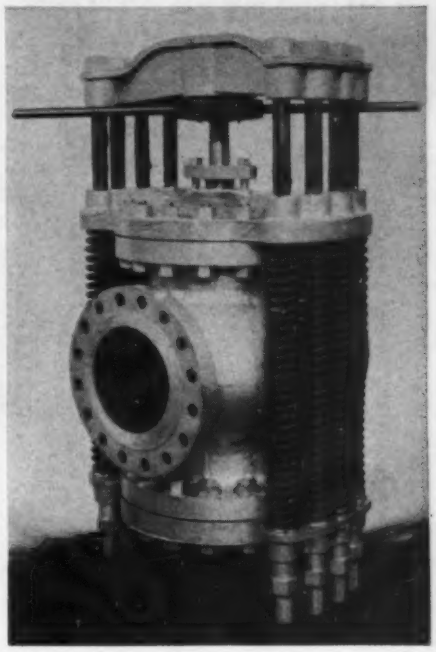
The Reeves Pulley Company has issued a profusely illustrated 16-page bulletin entitled "More Output for Defense" which gives a broad picture of the application of Reeves motodrive, vari-speed motor pulleys and variable-speed transmission gear in industries participating in the defense program. Illustrations show a diversified selection of machines and equipment and many installation views of this equipment in operation.

Gauges

A new 64-page 1942 Ashcroft Gauge catalog has just been issued by Manning, Maxwell & Moore, Inc. It contains listings of numerous new gauges, streamlined gauge cases, gauges for special services and a complete listing of Duragauges. In addition to these listings, the new catalog illustrates the various gauge testers and numerous accessories required by all gauge users.

Water Columns

Catalog No. 414, just released by The Reliance Gauge Column Company, describes safety water columns and accessories for working steam pressures up to 250 lb. This 16-page, two-color publication is profusely illustrated. Diagrammed installation instructions are given, together with dimension and selection tables.



Obituaries

Lieut-Comdr. W. D. La Mont, U.S.N. retired, inventor of the La Mont forced-circulation steam boiler, died late in January at his home in New York City at the age of 52. A Naval Academy graduate with the class of 1910, he became one of the early naval air pilots and during the first world war was an engineer officer at one of the naval bases. Resigning in 1924, he devoted his time to developing his patents.

William S. Murray, consulting engineer and member of the firm of Murray & Flood, Inc., New York, died after a brief illness at his home in New York City on January 9. Mr. Murray was perhaps best known to the power field as sponsor and chief engineer of the Superpower Survey carried on under Congressional authorization during the early 'twenties; also for his work in charge of electrification of the New Haven Railroad.

Philip Torchio, retired vice president and former chief electrical engineer of the Consolidated Edison Company, New York, died on January 14 at the age of 74. Born and educated in Italy, Mr. Torchio joined the Edison Electric Illuminating Company of New York (predecessor of the present company) in 1895.

Lieutenant Charles Keene, U.S.N., died at the Naval Hospital in Philadelphia on January 30. He was formerly in the Proposition Engineering Department of Combustion Engineering Company and about three years ago was transferred to the Philadelphia District Office of the company. An Annapolis graduate, he was called back into the service a year ago.

M. F. Neeson, superintendent of steam and hydroelectric production of the Alabama Power Company, died suddenly on January 4 in Birmingham. He had been with that company since 1918.

H. D. Savage died at the White Plains, N. Y., Hospital on February 9, following a brief illness. He was 61 years old. A native of Memphis, Tenn., Mr. Savage came to New York in 1914 as vice-president of American Arch Co. and later held the same position with the Locomotive Pulverized Fuel Co. This was subsequently taken over by Combustion Engineering Corp. of which organization he was vice-president from 1921 to 1928, and for a short period president. At the time of his death he was connected with the Raymond R. Beatty Realty Corp. of Scarsdale, N. Y.

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